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State of California
The Resources Agency

Department of
Water Resources

save water
DWR

Small Hydroelectric Potential at Existing Hydraulic Structures in California

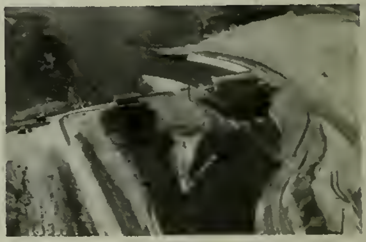
Bulletin 211
April 1981

Bulletin 211 was partially funded by a cooperative agreement (No. DE-FC-49-80-R9-10019.000) with the U.S. Department of Energy.

This Bulletin responds to Chapter 933, Statutes of 1978:

". . . It is in the best interests of the state that the existing dams and hydraulic structures identified in the Department of Water Resources' previous surveys be further studied to determine the feasibility and cost-effectiveness of equipping these dams and hydraulic structures with electric power-generating facilities . . ."

The legislation, Senate Bill 1834, was authored by Senator Alfred Alquist.



ON THE COVER: Turlock Lake Powerhouse, located on the Turlock Main Canal in Stanislaus County, is owned by the Turlock Irrigation District. This 3 300-kilowatt hydroelectric power plant generates 12.2 million kilowatthours of electricity annually. This amount of energy is equivalent to burning 20,000 barrels of oil annually in a fossil fuel plant.

Photo courtesy of Turlock Irrigation District.

Department of
Water Resources

Bulletin 211

Small Hydroelectric Potential at Existing Hydraulic Structures in California

April 1981

Huey D. Johnson
Secretary for Resources

The Resources
Agency

Edmund G. Brown Jr.
Governor

State of
California

Ronald B. Robie
Director

Department of
Water Resources

FOREWORD

To help meet California's increasing need for electricity, the Department of Water Resources is actively studying potential sources of hydroelectric energy in the State. The development of small hydroelectric generation facilities at existing hydraulic structures is one environmentally sound energy resource that merits the highest priority.

In 1978, the California Legislature enacted Senate Bill 1834 (Chapter 933, Statutes of 1978, authored by Senator Alfred Alquist) which directed the Department of Water Resources to study the feasibility and cost effectiveness of equipping existing dams and other hydraulic structures with electrical power-generating equipment.

The Department began its study by identifying 285 potential sites for developing small hydroelectric facilities through questionnaires sent to irrigation districts, Federal and State water agencies, and public and private utilities. These sites would have a total capacity of about 500 megawatts and an annual energy generation of 2.4 billion kilowatthours. Through this survey and subsequent studies, the Department determined that 240 out of 285 potential sites, representing 99 percent of the total potential capacity, would be cost effective by 1989. This could supply the residential needs of one million people and would eliminate the need of burning 4 million barrels of oil yearly in a thermal power plant.

In January 1980, Governor Edmund G. Brown Jr. established a task force headed by this Department and comprised of representatives from nine State agencies to support and encourage the construction of power plants at existing dams, canals, and pipelines. Through the efforts of this task force, the process for obtaining State permits and approvals for hydroelectric power plants has been streamlined. The Department of Water Resources, in cooperation with the U. S. Department of Energy, has also established an "Outreach Program" to assist developers with procedural requirements and to provide loan information for small hydroelectric projects. Information regarding hydroelectric development can be obtained by telephoning (916) 323-0103.

This study is a comprehensive analysis of small hydropower, and is a significant step towards establishing energy independence, not only in California, but also elsewhere in the nation. As part of meeting its goal of satisfying 70 percent of the State Water Project's energy needs from renewable resources, the Department of Water Resources has scheduled the construction of 15 small hydroelectric power plants at sites on the State Water Project.

Small hydro efforts are growing. As a result, the State should gain about 500 megawatts of small hydroelectric capacity within the next ten years. This is a significant step in achieving the State's and nation's energy goals.

Ronald B. Robie

Ronald B. Robie, Director
Department of Water Resources
The Resources Agency
State of California

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(bound separately).

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Portions of this report were prepared with the assistance of:

Contractor	Contract No.	Amount
John J. Boudreau	B-53267	$ 6,452
Lee Crisan	B-53814	2,500
James Hansen and Associates	B-52584	2,667
	B-53570	52,500
	B-53303	108,802
Total		$172,921

APPENDIXES (bound separately in a single volume)

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State of California
Department of Water Resources
CALIFORNIA WATER COMMISSION

The California Water Commission serves as a policy advisory body to the Director of Water Resources on all California water resources matters. The nine-member citizen Commission provides a water resources forum for the people of the State, acts as a liaison between the legislative and executive branches of State Government and coordinates Federal, State, and local water resources efforts.

SUMMARY

The Department of Water Resources studied the feasibility and cost effectiveness of retrofitting existing hydraulic structures within the State with facilities for generating hydroelectric power.

A statewide survey identified 285 sites--137 dams, 53 canals, and 95 pipelines--where hydropower could be developed. These sites offered a combined potential for generating 510 megawatts (MW) of power with an annual energy production of 2.4 billion kilowatthours (kWh).

The 285 sites were categorized into six groups, based on the type and size of existing hydraulic structure. From these, 49 sites were selected for field investigations, and preliminary feasibility studies were conducted at 28 of these representative sites. Based on these studies, the cost effectiveness of each site was determined, and these cost data were used to estimate the cost effectiveness of the remaining sites for which limited data were available.

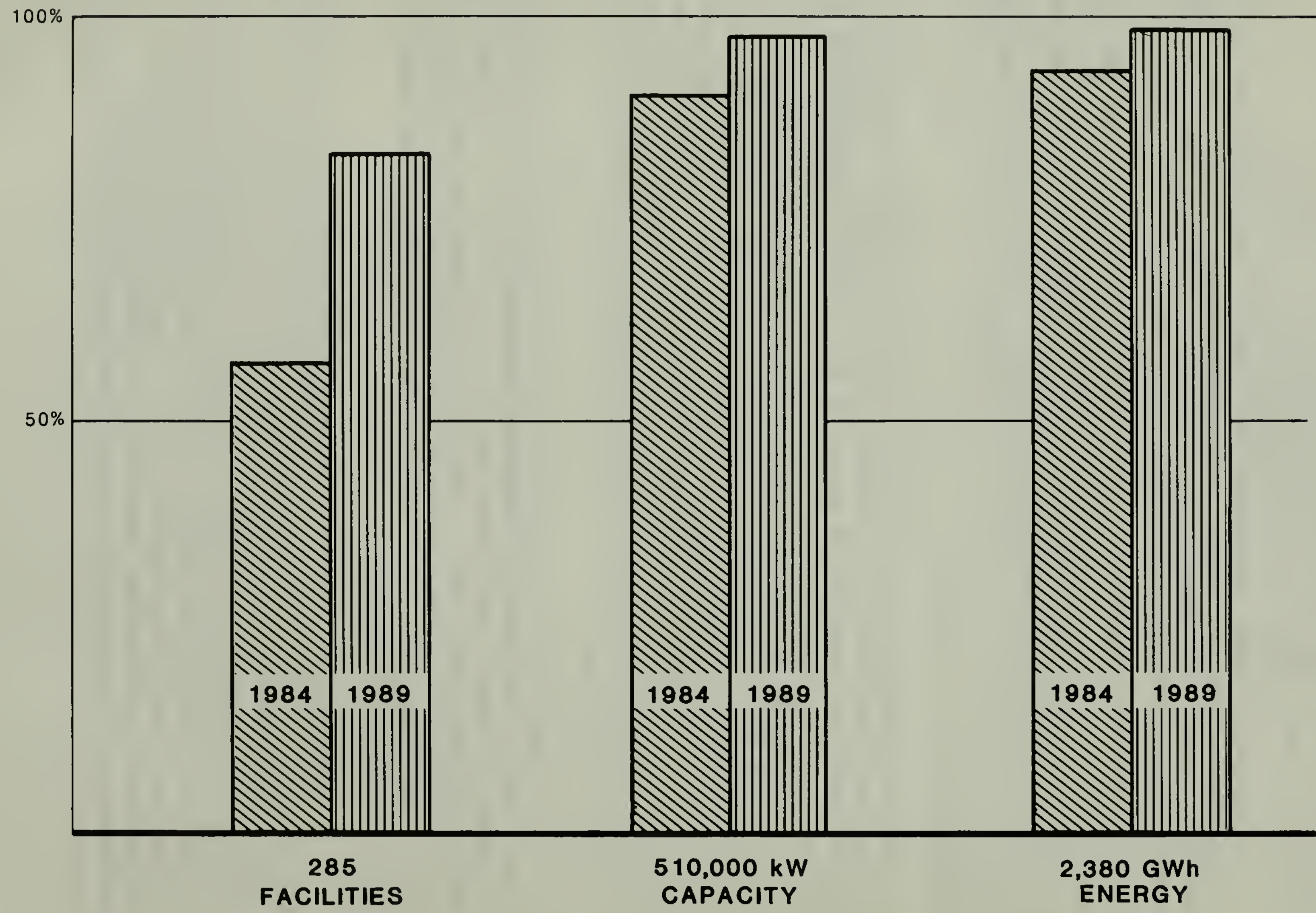
The study showed that 167 (59%) of the 285 sites are cost effective if developed immediately for initial operation in 1984. These sites represent an installed capacity of about 468 MW -- 92% of the potential power -- and an estimated annual generation of 2.25 billion kWh (95%). An additional 73 (26%) of the sites would be cost effective by 1989. These sites represent an installed capacity of 36 MW (7% of the potential power) and an annual generation of 120 million kWh (5%). Only 45 (15%) of the sites studied representing an installed capacity of 6 MW -- 1% of the potential power -- and an estimated annual generation 10 million kWh (0.4%) are less suitable for immediate development. These sites would have to operate at a loss for in excess of 5 years before becoming cost effective under current fuel cost projections.

Progress in the development of small hydroelectric projects is illustrated by the number of projects completed or under construction and the number of permit and license applications filed with the Federal Energy Regulatory Commission (FERC). Out of the 285 potential projects 80 facilities -- representing over 355 MW of the total installed capacity of 510 MW -- have been completed, are under construction, or have had applications filed for them with FERC.

The results of this study emphasize the value of utilizing all of our potential energy resources. Developing the small hydroelectric facilities identified here would make available over 2.4 billion kWh of electrical energy annually. If oil were used to generate this energy, 4 million barrels would be required each year. In addition, 2.4 billion kWh of electrical energy represents a value of approximately $120 million in revenue each year. Development of this resource would significantly reduce California's dependence on imported oil, provide a dependable, environmentally sound source of electrical energy, and would be an important contribution to the nation's goal for energy independence.

FIGURE 1

Figure 1. Number, Capacity, and Energy of Cost Effective Projects



CHAPTER I

INTRODUCTION

This bulletin reports the results of a study of the feasibility of developing small hydroelectric power-generating facilities at California's existing hydraulic structures, such as dams, canals, and pipelines. By identifying potential sites for such development and evaluating their cost effectiveness, the Department of Water Resources hopes to encourage private, as well as public, entities to invest in the state's energy future.

Although the Department only evaluated sites within the state, these hydraulic structures also typify those that commonly occur in other states. Because of this, the results of this study are freely transferrable nationwide, and the report's findings should be beneficial to any state that is concerned about its energy independence.

In 1974, a departmental report, "Hydroelectric Energy Potential in California" (Bulletin 194), identified potential sites for hydroelectric facilities that had a generation potential of more than 25 million kilowatthours annually. The report inventoried hydroelectric developments that had been studied previously, but those which might warrant reevaluation in view of quadrupling oil prices. Most of the projects required the construction of new dams and reservoirs or the enlargement of existing facilities.

Lake Berryessa (Monticello Dam), on Putah Creek in Napa County, is owned by the U. S. Water and Power Resources Service. A 16 000-kilowatt hydroelectric power plant at this site could generate 43 million kilowatthours of electricity per year. This amount of energy would supply the annual electrical residential needs of 20,500 people. (Photo by DWR Energy Division)

Figure 2 Potential Small Hydroelectric Sites at Existing Hydraulic Facilities

In 1976, the Department sent questionnaires to over 800 California water agencies, utilities, and federal agencies requesting them to identify and provide information on potential small hydroelectric projects that could be constructed at existing hydraulic facilities, such as dams, canals and pipelines. A report, "A Survey of Small Hydroelectric Potential at Existing Sites in California," was published as Bulletin 205 in June 1979 based on this information. It identified 212 potential hydroelectric projects that could be developed at existing installations.

The Legislative directive (SB 1834, authored by Senator Alquist) to conduct a feasibility study became more important during the past year than was originally anticipated in 1978. At the time of the first oil crisis in 1973, the average cost of oil used to generate electrical energy in California was $5 per barrel. The cost remained reasonably stable at about $15 per barrel from 1975 through 1978. After the political unrest in Iran in late 1978, the price of oil jumped. Shortages reappeared, and by late 1979 the price of oil increased to about $25 per barrel and even higher on the spot market. The average price of oil increased to about $30 per barrel by mid-1980.

Projections prepared by the California Energy Commission in late 1979 indicate substantial increases in the price of oil will continue until synthetic fuels become available. Since 50 percent of California's electricity is generated using oil, the costs of generating electrical energy will continue to increase. Thus California's potential hydroelectric resources become increasingly more valuable.

In 1980, questionnaires were sent to utilities, water agencies, and irrigation districts that did not reply to the 1976 survey. About 75 additional existing facilities were identified for a total of 285 locations where small power plants could be constructed (Figure 2).

Clear Lake Impounding Dam, on Cache Creek in Lake County, is owned by the Yolo County Flood Control and Water Conservation District. A 2 000-kilowatt hydroelectric power plant at this site could generate 7.5 million kilowatthours of electricity per year. This amount of energy would supply the annual electrical residential needs of 3,600 people. (Photo by DWR Northern District, Red Bluff)

Since it was not possible to investigate each of the 285 potential sites, the Department developed a three-phase evaluation program (Chapter III, Figure 6). During the first phase, the 285 hydraulic facilities were classified into six categories based on the size and type of facility. Forty-nine of these facilities were selected for field investigations during the second phase. These facilities were representative of the six categories. After visiting these facilities and assessing them, the Department selected 28 facilities which best represented most of the facilities in California. A preliminary feasibility study of each of these 28 facilities was conducted during the third phase. The information from the 28 studies was supplemented by 42 feasibility reports prepared by independent consultants hired directly by facility owners. The results of the Department's 28 preliminary feasibility studies are discussed in Appendix C; data taken from feasibility studies conducted by others are presented in Appendix D. The data from the 28 studies, supplemented by cost information from the reports prepared by independent consultants, were used to evaluate the cost effectiveness of all potential facilities in California. This assessment of statewide potential is discussed in Chapter III.

Small Hydroelectric Technology

Small hydroelectric technology was extensively developed in this country from the late 1800s into the 1940s. Very few small hydroelectric plants have been installed between 1950 and 1975, because of the more favorable economics of large steam-electric plants. In fact, about 3,000 hydroelectric plants have been retired from service during the period from 1930 to 1970. A recent study shows that as many as 2,150 of these plants representing 1 300 MW could readily be returned to production.

Lake Redding (ACID Diversion Dam), on the Sacramento River in Shasta County, is owned by the Anderson-Cottonwood Irrigation District. A 9 000-kilowatt hydroelectric power plant at this site could generate 50 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 85,300 barrels of oil annually in a fossil-fuel power plant.
(Photo by DWR Energy Division)

Over the past 30 years, small hydroelectric technical development also declined, and turbine manufacturing facilities were either abandoned or fell into general disuse. During this time, European and Asian manufacturers continued to manufacture small hydraulic turbines, but primarily for power generation locally or for use in remote areas.

Due to recent events, American manufacturers have renewed interest in supplying hydraulic turbines. Allis-Chalmers Company, a major manufacturer, has designed a line of standard horizontal tube-type turbines, which are available in ten sizes ranging between 50 kW and 7000 kW of capacity and for heads up to 18.3 metres (60 feet). Another manufacturer, James E. Leffel Company, has joined with Bofers-Nahab of Sweden and Tampella of Finland and is in the process of enlarging its American facilities to produce principally site-specific vertical-type turbines. The China National Machinery and Equipment Export Corporation plans to aggressively market its hydroelectric equipment in the United States. The Schneider Lift Translator Company builds a device in the United States for producing power under lowhead conditions. The device resembles a series of venetian blinds (hydrofoils) connected to an endless chain over a drum and shaft. The lift translator is available in sizes from 1 kW to 5 000 kW. Ossberger turbines (cross-flow) manufactured in West Germany are available for heads ranging from 1 metre to 200 metres (3 to 660 feet). The highest output per unit is about 1 000 kW. While not producing turbines at its own facilities, General Electric Company has arranged for Hitachi, a Japanese firm, to supply turbines for its generators. Although other American firms can supply hydraulic turbines in the 500 kW to 3000 kW range, the turbines used in new facilities would most probably be manufactured in Sweden, Canada, Switzerland, Norway, Austria, France, China, or Japan.

The principal characteristic of any hydroelectric facility is the combination of head and streamflow that is specific to its site. The head available at the site usually dictates the type of turbine to be used, and streamflow is an important factor in determining its capacity. The most efficient design for a particular hydroelectric site is one designed for the site's conditions. Standardized turbines can save time and manufacturing costs, but a hydraulic turbine operates most efficiently over a narrow range of operating conditions, and outside of that range, the efficiency of the installation decreases.

There are two general types of hydraulic turbines: the impulse turbine which has one or more jets that discharge water onto the buckets of a runner, and the reaction turbine, which is submerged in the streamflow and can be either a Francis type (mixed water flow) or propeller type (axial water flow). Both Francis and propeller turbines may be mounted horizontally or vertically. Propeller turbines can also be supplied with either fixed or variable pitch blades (the variable pitch propeller type is sometimes referred to as a Kaplan turbine).

Impulse turbines may have some application for small hydroelectric installations with very high heads, but for comparable head and capacity, the reaction turbine generally costs less to manufacture. More information on turbines is given in Appendix I.

Environmental Issues

Environmental degradation, a principal concern with most energy development projects, is generally not a serious problem with the installation of small hydroelectric facilities at existing dams, canals, or pipelines. Since these hydraulic structures are already in place, and the small hydroelectric units are relatively minor additions to them, only minimal environmental impacts occur. A potential impact on the environment can usually be avoided by thoughtful design and construction.

In a few cases where the impacts from secondary activities may have some significance, the impacts should be considered, case-by-case, separate from any impact the project itself might have. Construction of the project, for example, might generate dust and noise, increase local traffic erosion, silting, and turbidity in waterways, and remove vegetation. Any serious threat to the environment could be minimized by scheduling construction to avoid certain critical seasons and by exercising care.

Operation of the facility could also have some impact. The operation of generators could increase noise levels and increase minor emissions of ozone, but existing energy dissipaters at many facilities are often noisier than the turbines and generators together.

Various forms of wildlife could be affected by hydroelectric development. If the flow regime is changed this can affect fish. But turbine/generators can be installed without altering the flow pattern. Although turbines are generally less harmful to fish than energy dissipaters, fish can be injured or killed by passage through turbines. The Endangered Species Act requires the Federal Energy Regulatory Commission (FERC) to assure that the development of any site will not interfere with or destroy endangered species.

FERC has simplified licensing procedures, thereby greatly reducing the time required to process applications (Appendix F). Site developers, however, will have to comply with the California Environmental Quality Act (CEQA) and obtain several federal, state, and local approvals. The environmental assessment and approval process will require a minimum of one year (Chapter IV, Figure 13). In general, small hydroelectric recovery facilities can be installed and begin service within 30 to 36 months, as compared with the 10 to 15 years often necessary for major projects at new sites.

The overall impact of small hydroelectric development would be beneficial. Development can be combined with various fish and wildlife projects to create improved access for fishing, boating, and other recreational activities. Since hydroelectric power displaces power generated by nonrenewable resources, it conserves natural resources and reduces the need for more destructive activities such as mining and drilling.

Small hydroelectric development will contribute significantly to the expansion of our nation's energy resources in an environmentally responsible manner.

Economic Issues

The lack of a ready market for power generated by small hydroelectric facilities significantly deterred development prior to the enactment of the

Public Utility Regulatory Policies Act (PURPA) by Congress in 1978. PURPA and the policy of the California Public Utilities Commission (CPUC) created a market for this power by requiring electric utilities to purchase power from small power production facilities including hydroelectric projects at an "avoided cost." Basically, PURPA guarantees a market for power from small hydroelectric generation at a rate equal to the cost for the utility to generate the power itself or purchase the power from another source. In purchasing this power, the utility can thereby avoid having to produce or purchase the power. This avoided-cost pricing is discussed in Chapter II.

Generally, it will take about 24 months to prepare preliminary feasibility study, obtain state and local approvals, and a FERC license. This period accounts for about two-thirds of a project's development schedule, and 20 percent of the total project cost. Title IV of PURPA promotes the development of potential facilities by providing loans for the necessary feasiblity studies and license applications--if the project is not

Slab Creek Dam, on the South Fork of the American River in El Dorado County, is owned by the Sacramento Municipal Utility District. A 400-kilowatt hydroelectric power plant at this site could generate 3.0 million kilowatthours of electricity annually. This amount of energy would supply the annual electrical residential needs of 1,400 people. (Photo by DWR Division of Safety of Dams) feasible, the debt can be forgiven. The financing of projects is discussed more fully in Appendix H.

Small hydroelectric development can have a socioeconomic effect as well. A number of temporary jobs are created during the construction of a project. Afterwards, permanent jobs are created for workers who must maintain and operate the facility.

These projects provide excellent opportunities for training and employing the unemployed. The Comprehensive Employment and Training Act (CETA) provides federal funds for establishing hydroelectric power redevelopment projects that will employ and train unemployed youths.

Finally, small hydroelectric development will lessen the nation's balance-of-payments deficit by reducing oil imports; this, in turn, will reduce inflationary pressures. Besides decreasing the country's dependence on imported energy supplies, small hydroelectric facilities can allow individual communities to become more self-reliant in the production of energy. This dispersion of power-generating facilities will be most benefical to our nation's goal for energy independence and security.

Retrofitting Problems and Their Solution

Each potential small hydroelectric facility differs in the technical characteristics of the head and flow needed to produce power; they can also differ because of the intended uses of the existing hydraulic structure. These uses include flood control, irrigation, and domestic water supply.

Flood control dams use storage space in their reservoirs to absorb flood flows; releases from these reservoirs tend to be large and short lived. In a single-purpose flood control project, only minimal flows are released downstream for irrigation and in-stream uses during most of the year. The heavy flows released for short periods during flood control cannot be used economically to produce hydroelectric power. Flood control and power generation could be coordinated to use reservoir storage capacity more efficiently through agreements with the operators of the facility.

The original designs of many flood control facilities did not provide for the tunnels, conduits, or waterways necessary for hydroelectric generation. The problems this creates must be studied on a case-by-case basis.

Irrigation dams are designed to conserve winter and spring runoff for release later during the summer. Generally, irrigation releases are largest from May through July and taper off from August through October, depending on the amount of storage available. Irrigation facilities are particularly suited to being retrofitted for hydroelectric generation because the heads and flows are significant and the major releases correspond with peak summer demand for electric power. In many cases, the installation of hydroelectric facilities at irrigation dams requires only minor alterations to the existing facility and its operation.

Water distribution systems use pipelines to transport water from one place to another. The cost usually limits the size of pipe used in most cases. The limited power head that does exist is often further reduced by the friction of the water flowing in the pipes. Irrigation and municipal pipelines carry heavier flows during summer months; therefore, the hydraulic head available for the generation of electric power can be lower during the season when peak demand for electrical energy occurs.

Pipelines are often constructed of sections of precast concrete and serve as enclosed waterways. This type of conduit cannot be pressurized for use as a penstock for carrying the water to a power plant.

The addition of hydroelectric power generation capacity at existing hydraulic structures must be compatible with the existing operation of the facility. At a flood control dam for example, if the existing outlet conduit is to be used as a penstock, modification must be accomplished without restricting full-flood flow releases. The existing outlet works and specific site conditions will determine how this might be accomplished.

For irrigation dams, the additional hydroelectric generation unit itself can be the by-pass around the existing outlet valve that controls the irrigation releases. With an irrigation canal, sufficient hydraulic capacity must be available at the site to allow the full canal flow to pass if an outage of the hydroelectric units occurs during the irrigation season.

Hydraulic turbines can be operated over a range of about 50 to 115 percent of the rated flows and over a range of about 50 to 150 percent of the rated head. For some sites where large variations occur, this equipment limitation can restrict the amount of electrical energy actually generated to less than the potential generation calculated for the facility.

Physical and Hydrologic Requirements

The amount of electrical energy that can be produced annually is the single most important factor in determining the cost effectiveness of developing hydroelectric power generation at an existing facility. The amount of generation is related directly to how much water is available, for how long, and under what hydraulic head.

The physical layout of an existing structure must be evaluated first. The data that must be obtained include the physical dimensions of the dam, canal, or pipeline; maximum and minimum hydraulic heads; tailwater level; rating curves for outlets and pipelines; relationships between the storage capacity of the reservoir and its elevation; and other operational criteria such as flood control restrictions on the reservoir, the amount and duration of flows from the facility, and the minimum flow requirements for instream uses.

Once the physical parameters of a facility are known, hydrologic data must be obtained before the average annual electrical generation can be calculated. These data include determining the drainage area; average daily or monthly flows over a ten- to fifty-year period; flow duration curves, conduit and outlet rating curves, effective hydraulic head-duration data; evaporation and seepage losses; and minimum instream flow requirements.

Daily flow data can be used to construct a flow-duration curve from which the facility's capacity and energy potential can be determined, and the annual electrical generation can be estimated. At most facilities, flow records have been kept since the facility was built and are available from the owner. In a few cases where these records are not available, records can be obtained from stream gaging stations and reservoir water recorders near the specific site. Some of these records are also available through various government agencies. The U. S. Geological Survey publishes continuous flow data on major streams and rivers; other agencies such as the U. S. Army Corps of Engineers, the Water and Power Resources Service, and the Soil Conservation Service also maintain stream flow records. This flow data, along with data published by various state agencies, usually can be found in libraries maintained by universities, by the state, or by various federal agencies.

Status of Facility Development

The progress and status of small hydroelectric projects are summarized in Tables 1 and 2. Out of 285 potential projects, 80 facilities--representing about 355 MW of the total installed capacity of 510 MW (70 percent)--have been completed, are under construction, or are in some other stage of development.

In addition to the FERC permit and license applications the number of sites being considered for development are also indicated by the number of U. S. Department of Energy (DOE) loan applications, and California Energy Commission (CEC) grant applications. Table 3 lists the applications for DOE licensing and feasibility loans, and Table 4 lists the feasibility studies co-funded by the CEC.

Table 1. Summary of the Status of Small Hydroelectric Projects at Existing Facilities

Status (January 1981)	Number of Facilities	Capacity (kW)	Energy (GWh/yr)
Construction Complete	8	31 200	162
Under Construction	5	34 600	223
FERC License or Exemption Issued	13	75 800	311
Applications Filed for FERC License or Exemption	4	19 530	69
FERC Preliminary Permits Issued	31	125 785	520
Applications Filed for FERC Preliminary Permits	19	68 555	295
TOTAL	80	355 470	1 580

Table 2. Detailed Analysis of the Status of Small Hydroelectric Projects at Existing Facilities

Owner/Project Name	Capacity (kW)	Energy (GWh/yr)	
CONSTRUCTION COMPLETE			Date completed
California Department of Water Resources			
Del Valle No. 1	5	0.04	10/80
The Metropolitan Water District of Southern California			
Foothill Feeder	9 100	61.3	10/80
Greg Avenue	1 000	4.5	6/80
Lake Mathews	4 900	18.6	8/80
Nevada Irrigation District			
Rollins Dam	12 000	60.0	6/80
Richvale Irrigation District			
Richvale Canal	100	0.3	8/80
Turlock Irrigation District			
Turlock Main Canal Drop No. 1	3 300	12.2	7/80
Turlock Main Canal Drop No. 9	1 100	4.7	10/79
TOTAL	31 200	161.6	
UNDER CONSTRUCTION			Scheduled completion date
Pacific Gas and Electric Company			
Volta No. 2 Powerhouse	1 000	5.0	1981
The Metropolitan Water District of Southern California			
San Dimas	9 900	68.2	2/81
Sepulveda Canyon	8 600	56.2	9/81
Venice	10 000	60.0	12/81
Yorba Linda Feeder	5 100	33.5	6/81
TOTAL	34 600	222.9	
FERC LICENSE OR EXEMPTION ISSUED			Date issued
California Department of Water Resources			
Cottonwood No. 1	17 000	115.0	3/22/78
Thermalito Afterbay River Outlet	13 000	43.0	9/30/80
Merced Irrigation District			
Canal Creek	900	3.3	11/10/80
Escaladian Drop (Canal)	300	0.8	11/10/80
Fairfield Drop (Canal)	1 000	2.8	11/10/80
Richard B. Parker (on Main Canal)	2 800	9.2	8/18/80
Oroville-Wyandotte Irrigation District			
Sly Creek Dam	13 200	48.2	12/11/80
Sacramento Municipal Utility District			
Slab Creek	400	3.0	9/10/80

Table 2. Detailed Analysis of the Status of Small Hydroelectric Projects at Existing Facilities (Continued)

Owner/Project Name	Capacity (kW)	Energy (GWh/yr)	
FERC LICENSE OR EXEMPTION ISSUED (Continued)			Date Issued
South San Joaquin Irrigation District			
Frankenheimer Drop (Canal)	4 700	18.7	11/10/80
Woodward Dam	2 300	6.9	8/18/80
Turlock Irrigation District			
Turlock Main Canal Drop No. 6	200	0.8	1/02/81
Upper Dawson Project	4 000	15.9	11/10/80
U.S. Water and Power Resources Service			
Lake Berryessa (Montecello Dam)	16 000	43.0	1/29/81
TOTAL	75 800	310.6	
APPLICATIONS FILED FOR FERC LICENSE OR EXEMPTION			Scheduled completion date
California Department of Water Resources 1/			
Antelope Dam	450	1.4	3/85
Castaic Outlet	275	1.4	3/84
Cottonwood No. 2	12 000	90.0	7/88
Lake Davis (Grizzly Valley Dam)	500	1.5	1/85
Del Valle No. 2	400	1.1	7/85
Frenchman Dam	450	1.0	9/84
Las Flores Turnout	200	0.7	9/85
Mojave Siphon No. 1 (Silverwood Lake Inlet)	5 000	42.4	7/83
Mojave Siphon No. 2 (Silverwood Lake Inlet)	5 000	42.4	7/88
Palermo Outlet	400	2.0	1/84
Pyramid Outlet	1 000	4.0	7/84
Thermalito Diversion Dam	3 000	23.0	9/83
East Bay Municipal Utility District			
Camanche Dam	10 680	35.0	1983
Placer County Water Agency			
Hell Hole Dam	550	3.0	1982
Santa Barbara, City of			
Gibraltar Dam	1 500	4.0	--
South Sutter Water District			
Camp Far West Dam	6 800	26.9	--
TOTAL	19 530	68.9	

1/ Except for Cottonwood No. 2 and Mojave Siphon No. 1, applications for all Department's projects are scheduled to be filed by July 1981.

Table 2. Detailed Analysis of the Status of Small Hydroelectric Projects at Existing Facilities (Continued)

Owner/Project Name		Capacity (kW)	Energy (GWh/yr)	Date
FERC PRELIMINARY PERMITS ISSUED	Issued to			
Anderson-Cottonwood I.D.				
Lake Redding	City of Redding	14 000	50.0	3/19/79
Browns Valley Irrigation District				
Harding Canal	Owner	1 900	6.6	7/22/80
Merle Collins Reservoir (Virginia Ranch Dam)	Owner	600	5.6	7/22/80
Flat Water Ditch Company				
Saeltzer Dam	City of Redding	875	6.5	2/27/81
Humbolt Bay M.W.D.				
Ruth Reservoir (R.W. Matthews Dam)	Owner	4 000	14.2	1/16/81
Monterey County FC&WCD				
San Antonio Dam	Owner	6 000	26.0	6/21/79
Nevada Irrigation District				
Lake Combie	Owner	1 000	4.0	3/26/79
Oakdale and South San Joaquin I.D.				
Sand Bar Project	Owner	12 000	70.0	5/07/80
San Bernardino Valley MWD				
Lytle Creek Turnout	Owner	1 300	8.0	10/29/80
Santa Ana Low Turnout	Owner	1 400	4.0	10/29/80
Sweetwater Turnout	Owner	900	2.0	10/29/80
Waterman Canyon Turnout	Owner	4 000	7.0	10/29/80
Siskiyou County FC&WCD				
Lake Siskiyou (Box Canyon Dam)	Owner	4 000	20.0	1/01/79
Southern California Edison				
Paoha Project	Joseph M. Keating	500	1.0	11/14/80
U.S. Army Corps of Engineers				
Black Butte Dam	City of Santa Clara	5 000	25.0	10/14/80
Hensley Lake (Hidden Dam)	Madera Irrigation Dist.	1 300	4.0	9/10/80
H.V. Eastman Lake (Buchanan Dam)	Madera Irrigation Dist.	3 000	9.0	9/10/80
Lake Mendocino (Coyote Dam)	City of Ukiah	4 000	10.0	8/02/79
New Hogan Dam	Calaveras Co. W.D.	2 000	8.0	11/06/79
Success Dam	Lower Tule River Irrig. Dist.	4 000	12.0	9/04/80
U.S. Forest Service				
Hume Lake (Dam)	Lewis Evans	1 050	4.6	10/14/80
U.S. Water and Power Resources Services				
Boca Creek Dam	Truckee-Donner PUD	1 500	7.0	4/29/80
Folsom Lake Pipeline	San Juan Suburban Water Dist.	500	2.4	10/10/80

Table 2. Detailed Analysis of the Status of Small Hydroelectric Projects at Existing Facilities (Continued)

Owner/Project Name		Capacity (kW)	Energy (GWh/yr)	Date
FERC PRELIMINARY PERMITS ISSUED (Continued)	Issued to			
U.S. Water and Power Resources Services (Continued)				
Madera Canal				
Station 980+65	Madera Irrigation Dist.	1 750	5.5	9/04/80
Station 1064+67	Madera Irrigation Dist.	560	1.9	9/04/80
Station 1910+60	Madera Irrigation Dist.	650	2.6	9/04/80
Millerton Lake (Friant Dam)	Terra Bella Irrigation Dist.	23 000	100.0	5/15/80
Prosser Creek Dam	Truckee-Donner PUD	1 000	3.5	4/29/80
Red Bluff Diversion Dam	City of Redding	14 000	70.0	5/08/80
Stony Gorge Dam	City of Santa Clara	6 000	18.0	10/10/80
Whiskeytown Dam	City of Redding	4 000	12.5	3/25/80
TOTAL		125 785	520.9	
APPLICATIONS FILED for FERC PRELIMINARY PERMIT	Applicant			
City of Bakersfield and Kern Delta W.D.				
Beardsley Canal Headworks Structure	Owner	200	3.0	11/05/80
Beardsley Diversion Structure	Owner	800	0.8	11/05/80
Rocky Point Diversion (Carrier Canal Project)	Owner	660	2.5	11/05/80
Edward S. Cruz and William L. Beavers				
Cottonwood Canyon and Lone Tree Creek	Owner	800	3.7	1/14/81
George Costa				
Trinity Tunnel (Del Loma)	Hydro Development, Inc.	600	4.5	11/25/80
Oakdale and South San Joaquin I.D.				
Goodwin Dam	Owner	4 920	20.8	10/09/80
Pacific Gas and Electric Company				
Lake Pillsbury (Scott Dam)	City of Ukiah	5 000	15.0	12/15/80
Redding, City of				
Soeltzer Dam	Owner	875	6.5	10/29/80
U.S. Army Corps of Engineers				
Isabella Dam 1/	California Department of Water Resources	8 000	18.5	6/16/80
	Sequoia Energy Corporation	2 300	11.5	7/11/80
	North Kern Water Storage District	8 000	17.0	10/02/80

1/ Competing applications.

Table 2. Detailed Analysis of the Status of Small Hydroelectric Projects at Existing Facilities (Continued)

Owner/Project Name		Capacity (kW)	Energy (GWh/yr)	Date
APPLICATIONS FILED for FERC (Continued)				
PRELIMINARY PERMIT	Applicant			
U.S. Army Corps of Engineers (Continued)				
Lake Clementine 1/	City of Redding	12 000	63.5	11/12/80
(North Fork Dam)	City of McFarland and Western Renewable Resources, Inc.	11 000	60.0	7/17/80
	City of Santa Clara	12 000	60.0	2/23/81
Lake Kaweah (Terminus Dam)	Kaweah Delta Water Conservation District	9 500	30.2	1/08/81
Warm Springs Project 1/	City of Ukiah	3 000	15.0	5/27/80
	Sonoma County W.D.	3 000	15.0	8/25/80
U.S. Forest Service				
Lost Creek Project	Floyd N. Bidwell	1 800	10.0	12/15/80
United Water Conservation Dist.				
Lake Piru (Santa Felicia Dam)	Fluid Energy Systems	3 600	7.8	9/16/80
U.S. Water and Power Resources Service				
East Park Dam 1/	City of Santa Clara	900	2.2	9/29/80
	Orland Unit Water Users Association	1 600	4.0	1/08/81
New Siphon Drop 1/	Western Water Power, Inc.	1 400	11.3	10/03/80
(Yuma Project)	Enagenics	4 040	21.2	1/09/81
Palo Verde Diversion	Mitchell Energy Company	8 700	53.0	1/12/81
Sly Park Dam 1/	Continental Hydro Coorporation	570	2.1	12/09/80
	El Dorado Irrigation District	800	3.0	12/22/80
Stampede Dam 1/	American Hydroelectric Development Corporation	3 000	16.0	1/14/81
	Western Water Power, Inc.	1 800	13.2	1/06/81
Yolo County Flood Control and Water Conservation District				
Clear Lake Impounding Dam	Owner	2 000	7.5	1/27/81
TOTAL		68 555	294.8	

1/ Competing applications.

Table 3. U. S. Department of Energy Feasibility and Licensing Loans

Application No.	Project	Owner/Operator	Date Rec'd
Feasibility Loans			
F09001 1/	Fresno Main Canal	Fresno Irrigation District 1568 North Millbrook Ave. Fresno, CA 93703	8/31/79
F09002 1/	New Hogan Dam	Calaveras County Water Department 427 East Street San Andreas, CA 95249	9/26/79
F09003 1/	Jackson Meadows Bowman Dam	Nevada Irrigation District P. O. Box 1019 Grass Valley, CA 95945	10/09/79
F09004 1/	Combie Dam	Nevada Irrigation District (see above)	10/09/79
F09005 1/	Lake Siskiyou	Siskiyou County Flood Control Department 305 Butte Street Yreka, CA 96097	10/12/79
F09006 1/	San Antonio Dam	Monterey County Flood Control Department P. O. Box 930 Salinas, CA 93902	10/25/79
F09007 1/	Ruth Lake	Humboldt Bay Municipal Water District 828 Seventh Street Eureka, CA 95501	11/28/79
F09008	Semitropic Intake Canal	Semitropic Water Storage District 1340 F Street Wasco, CA 93280	1/12/80
F09009 1/	Lyons Dam	Tuolumne County Water District No. 2 53 W. Bradford Sonora, CA 95370	1/25/80
F09010 2/	Barrett Dam	City of San Diego 202 C Street San Diego, CA 92101	2/03/80

1/ Loan approved
2/ Loan rejected

Table 3. U.S. Department of Energy Feasibility and Licensing Loans (Continued)

Application No.	Project	Owner/Operator	Date Rec'd
F09011 2/	Sutherland Dam	City of San Diego 202 C Street San Diego, CA 92101	2/03/80
F09012 1/	Madera Canal	Madera Irrigation District 12152 Road 28 1/4 Madera, CA 93637	2/11/80
F09013 2/	Hume Lake Dam	Lewis Evans P. O. Box 820 Kings Canyon National Park CA 93633	3/03/80
F09014 1/	Virginia Ranch Dam	Browns Valley Irrigation District P. O. Box 6 Browns Valley, CA 95918	3/19/80
F09015 1/	Hidden Dam	Madera Irrigation District (see above)	4/10/80
F09016 1/	Buchanan Dam	Madera Irrigation District (see above)	4/25/80
F09017 1/	Whitewater River	Culver Nichols 111 W. El Alameda P. O. Box 580 Palm Springs, CA 92262	5/08/80
F09018 1/	Black Butte Dam	City of Santa Clara 1500 Warburton Ave. Santa Clara, CA 95050	5/12/80
F09019 1/	Stony Gorge Dam	City of Santa Clara (see above)	5/21/80
F09023	Stumpy Meadows Reservoir	Georgetown Divide Public Utility District P. O. Box 338 Georgetown, CA 95634	9/29/80

1/ Loan approved
2/ Loan rejected

Table 3. U. S. Department of Energy Feasibility and Licensing Loans (Continued)

Application No.	Project	Owner/Operator	Date Rec'd
F09024	Carrier Power Project	City of Bakersfield 1501 Truxton Ave Bakersfield, CA 93301	11/25/80
F09025	Concow Project	Thermalito and Table Mountain Irrigation Districts 710 Grand Avenue Oroville, CA 95965	12/03/80
F09026	Scotts Flat Dam	Nevada Irrigation District P. O. Box 1019 Grass Valley, CA 95945	12/08/80
F09027	English Meadows Dam	Nevada Irrigation District (see above)	12/08/80
F09028	Lundy Reservoir	Joseph M. Keating Keating Associates 847 Pacific Street Placerville, CA 95667	12/18/80
Licensing Loans			
L09001 1/	Lake Mendocino	City of Ukiah 203 S. School Street Ukiah, CA 95982	11/02/79
L09002 1/	Friant Dam	Friant Power Authority Terra Bella Irrigation District 2479 Ave. 95 Terra Bella, CA 93270	11/30/79
L09003	New Hogan Dam	Calaveras County Water District 427 East St. Charles San Andreas, CA 95249	10/07/80
L09004	Lake Siskiyou	Siskiyou County Department of Public Works 305 Butte Street Yreka, CA 96097	10/21/80
L09005	Lake Combie	Nevada Irrigation District P. O. Box 1019 Grass Valley, CA 95945	12/08/80

1/ Loan approved
2/ Loan rejected

Table 4. California Energy Commission Feasibility Study Grants

Owner/Developer	Site
Amador County Water Agency	Central Amador Water Project
Calleguas Municipal Water District	Conejo Pump Station
Chowchilla Water District	Madera Canal Station 980+65 (WPRS)
El Dorado Irrigation District	Water Distribution System
El Segundo, City of	Pressure Reducing Station
Irvine Ranch Water District	Irvine Lake Pipeline (Rattlesnake Reservoir)
Lockheed Missiles & Space Co., Inc.	Big Creek Powerhouse Rehabilitation
North Tahoe Public Utility District	Griff Creek-Mt. Baldy Springs Project
Orange Cove Irrigation District	Sand Creek Check
Paradise Irrigation District	Paradise Reservoir
Redlands, City of	Highland Avenue Pumping Plant Redlands Water Treatment Plant
San Bernardino Valley Municipal Water District	Santa Ana Low Turnout Sweetwater Turnout
San Diego County Water Authority	Treatment Plants & Tunnel
San Gabriel Valley MWD	Devil Canyon-Azusa Pipeline
San Juan Suburban Water District	Treatment Plant to Distribution System
Truckee-Donner Public Utility District	Boca Dam (WPRS) Prosser Creek Dam (WPRS)
Whitewater Canyon Mutual Water Co.	Whitewater Canyon Irrigation System

Antelope Dam, on Indian Creek in Plumas County, is owned by the California Department of Water Resources. A 450-kilowatt hydroelectric power plant at this site could generate 1.4 million kilowatthours of electricity annually. This amount of energy is equivalent to burning 2,400 barrels of oil in a fossil-fuel plant. (DWR photo 3759-7)

CHAPTER II

THE PURCHASE OF SMALL HYDROELECTRIC POWER BY UTILITIES

Historically, a producer of small hydroelectric power wishing to market the energy produced, faced three major obstacles. Utilities were often unwilling to purchase the energy or to pay a reasonable price. Secondly, some utilities charged unreasonably high rates for providing back-up or standby service to customers who produced and used some of their own power. Often, these utilities also heavily discounted the value of such generation when calculating dependable capacity and reserves, and charged high wheeling (transmission) costs. Lastly, a small power producer who sold generation to a utility also ran the risk of being classified as an electric utility and thus becoming subject to state and federal regulation.

Until very recently, these obstacles discouraged the development of new small hydroelectric power facilities. Now, electric utilities are required to purchase the generation from small hydroelectric projects at a price equal to the costs that the utilities would incur producing the power themselves, or purchasing this amount of energy from other sources. A developer can, of course, use the energy generated for his own purposes without penalty.

Pertinent Legislation

The Public Utility Regulatory Policies Act of 1978 (PURPA) significantly changed the method for determining the value of energy generated by small power production facilities and cogeneration facilities, and also changed the requirements for electric interconnection and the wheeling of power produced by such facilities. The sections of PURPA which are particularly pertinent to small hydroelectric projects are Sec. 201, which defines a qualifying facility; Sec. 210, which defines the rates at which a qualifying facility can sell its energy; and Title IV, which provides loans for conducting feasibility studies and for licensing.

The impact of PURPA on the development of small hydroelectric generation is only now beginning to be felt. The Federal Energy Regulatory Commission (FERC) is in the process of establishing requirements and procedures that will filter down to the utilities and state regulatory agencies.

California is ahead of most other states in implementing some of the policies established by PURPA. The California Public Utilities Commission (CPUC) investigated Pacific Gas and Electric Company's (PGandE) resource plan and its alternative plans, their ratemaking implications, and the options available with each plan (CPUC Order Instituting Investigation No. 26, OII-26). The CPUC ordered PGandE to publish cogeneration rates based on its avoided cost and authorized the utility to purchase power from cogeneration facilities at those rates (CPUC Decision 91109, December 19, 1979). On February 4, 1980, PGandE announced that it would purchase energy from cogenerators and small power producers. The CPUC also extended the avoided-cost principle of Decision 91109 to the other CPUC-regulated electric utilities in California (CPUC Resolution E-1872, March 4, 1980).

Figure 3. Cost of Oil-Fired Generation at PG&E's Most Efficient Steam Plants

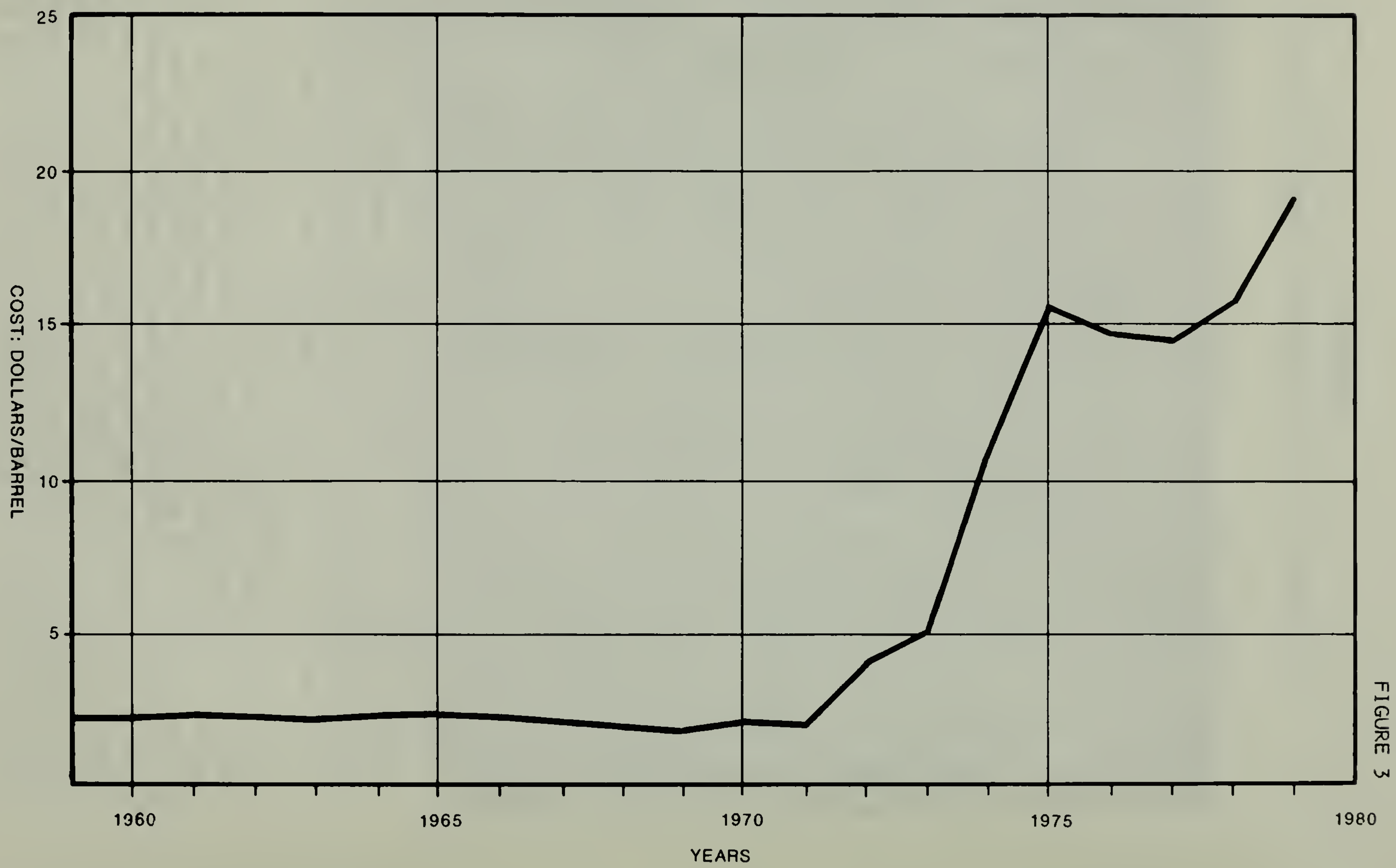


FIGURE 3

These include Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Pacific Power and Light (PP&L), Sierra Pacific Power, and CP National.

All of these electric utilities were directed to publish interim offers to buy electricity from cogenerators and small power producers pending the completion of CPUC rulemaking in compliance with PURPA. Standard price offers specific to small hydroelectric facilities (under 100 kW and over 100 kW) have been developed by PGandE; SCE, SDG&E, CP National, PP&L, and Sierra Pacific Power have developed similar price offers applicable to small hydroelectric power producers. The purchase of electricity from small hydroelectric producers by these utilities will be based on these price offers pending final implementation of PURPA by the CPUC.

The CPUC instituted a generic proceeding (OIR-2) to implement PURPA. This order will establish standards governing the prices, terms, and conditions of the utilities' purchases of electric power from cogeneration and small power production facilities. Owners or developers of qualifying facilities (QF) can accept the standard offers now available or can negotiate an agreement with the utilities on some other basis. In addition, the CPUC requested utilities to vigorously pursue making agreements with small power producers. To facilitate this activity, while OIR-2 is in progress, the CPUC staff is encouraging utilities and the owners or developers of QFs to agree to modify their contracts to conform with any standards adopted in OIR-2. Summaries of the power-purchase agreements for PGandE, SCE, and SDG&E are included in Appendix G.

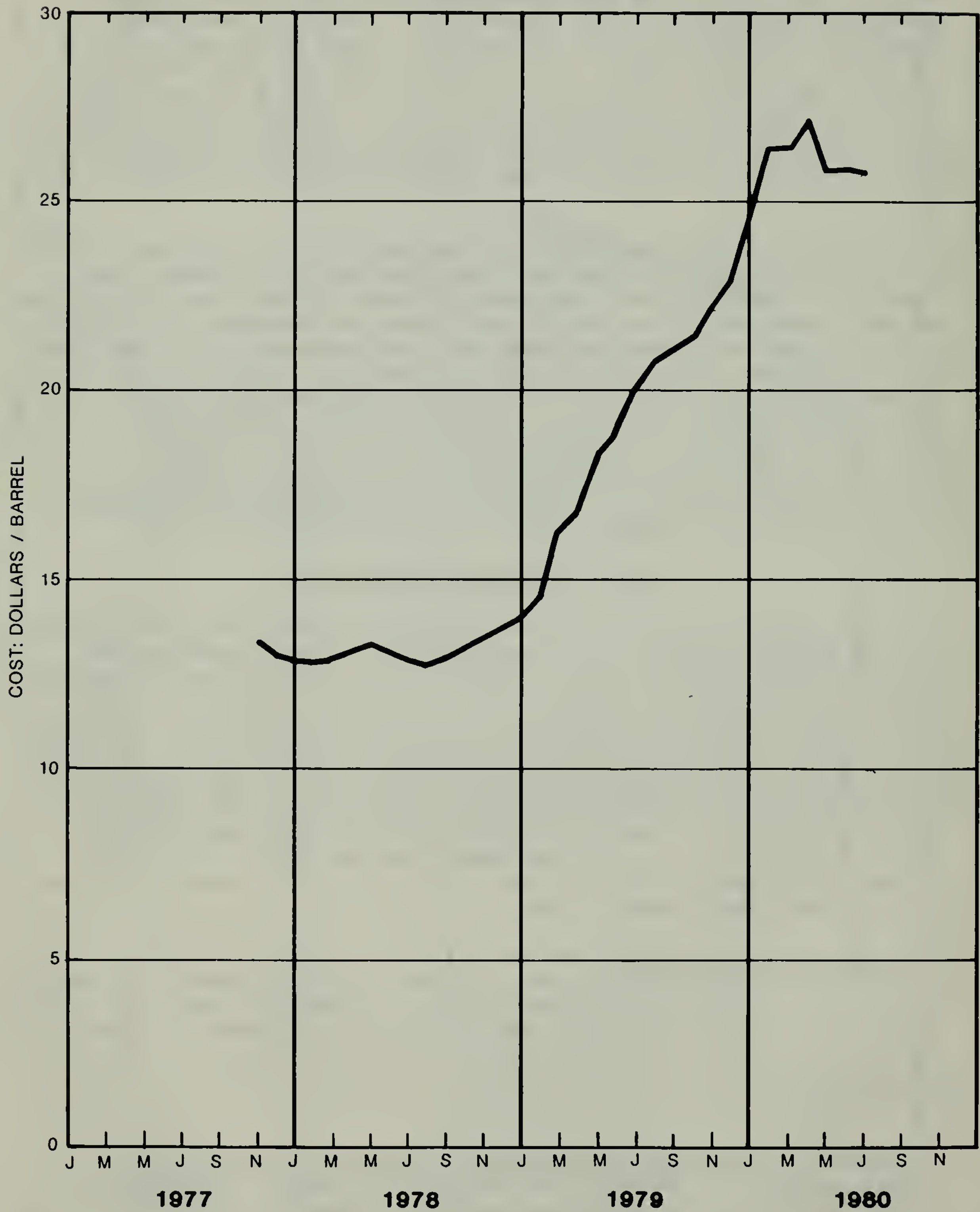
Cost of Alternative Generation

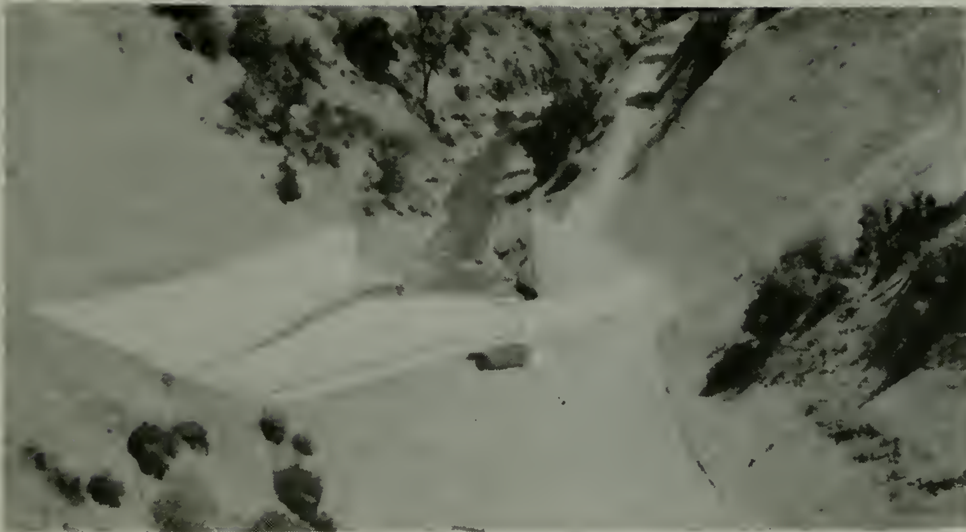
According to Section 210 of PURPA and the standard set forth by CPUC Decision 91109, the alternative generation from a small hydroelectric project can cost no more than the energy a utility would have to generate itself or purchase from another source. Since the utility can "avoid" producing this power by purchasing it, its cost is called the "avoided cost". The avoided-cost standard encourages the development of renewable resources, such as biomass, wood waste, refuse, and falling water, thus reducing our dependence on foreign oil. In California, and elsewhere, small hydroelectric projects will produce electrical energy that would otherwise be produced by oil-fired generating facilities. Thus, the avoided cost of energy will be related directly to the current and future cost of fossil fuel, primarily oil.

Historical Costs of Energy. The cost of oil has increased dramatically from about $2 a barrel in the 1960s to about $26 by mid-1980. The average cost of oil burned to produce electricity at PGandE's six most-efficient steam-electric power plants from 1959 through 1979 is shown in Figure 3. The cost of electrical energy produced by these oil-fired steam plants has increased from about 0.4 cents per kWh in the early 1960s to 3 cents per kWh in 1979.

Because of the rapidly rising price of crude oil and the time lag between purchase and actual use of this oil to generate electricity, the average annual cost may be misleadingly low. Thus, while the average cost of oil for electricity generation at PGandE's power plants during 1979 was

Figure 4 Cost of Oil Burned for Electric Generation
Middletown Station – Hartford Electric Lighting Company
Hartford, Connecticut





Indian Valley Dam, on a tributary of Cache Creek in Lake County, is owned by the Yolo County Flood Control and Water Conservation District. A 3 200-kilowatt hydroelectric power plant at this site could generate 7.2 million kilowatthours of electricity per year. This amount of energy would supply the annual electrical residential needs of 3,400 people.
(Photo by DWR Energy Division)

calculated to be about $18.20 per barrel, the actual cost during the last quarter of 1979 was about $21.50 per barrel.[1/]

The world market price for oil has increased even more during the first half of 1980. In the second quarter of 1980, Saudi Arabia increased its oil price from $26 to $28 per barrel. Although other oil-producing countries charge even more, the Saudi Arabian price generally reflects the average cost of all oil burned in the United States to produce electrical energy. The increase to $28 per barrel will be partially reflected in the 1980 cost of electrical energy, and fully reflected in the 1981 average cost. The actual cost of oil burned to generate electricity at a cycling steam-electric plant in the northeastern United States is comparable to the cost of oil used in California (Figure 4).

Projected Energy Costs. Reasonable estimates of the future prices for oil must be obtained in order to calculate the benefits or losses of capital investment in small hydroelectric facilities. The future prices of energy have been estimated in this report using figures supplied by the California Energy Commission (CEC) and other knowledgeable sources.

The CEC is conducting a continuing investigation into the cost and supply of fuels. In a comprehensive report, discussing supply availability and the projected costs of fuels,[2/] the CEC staff stated, "Continuing

1/ Estimated from energy rates developed by PGandE as a result of CPUC Decision 91109.

2/ Staff Draft Report. "Fuel Price and Supply Projections 1980-2000," California Energy Commission Publ. P102-79-014. November 1979.

international chaos indicates that any lessons to be learned from historic trends can be rapidly overshadowed by geopolitical shifts and [an] essentially complete disregard for free market forces. As the price and supply of oil to California [are] is shaped much more by world forces than by any internal dynamic[s] of supply and demand, the task of predicting our future oil availability/price is extremely difficult."

Although California is the fourth largest producer of oil and gas in the United States, about two-thirds of the State's energy supplies are imported.

The CEC report predicts substantial increases in the price of oil, because it is much less costly to increase oil- producing capacity in Saudi Arabia than to produce heavy crude oil in Venezuela or oil shale in Colorado. The average production cost in Saudi Arabia is probably less than $2 per barrel, while new Venezuelan oil would cost about $15 per barrel to produce; alternative fuels derived from coal would cost about $30 to $35 per equivalent barrel of oil (in 1979 dollars). Thus, Middle Eastern producers would probably maintain price levels low enough to preclude stimulating the development of alternative sources oil production or of alternative fuels.

Stony Gorge Dam, on Stony Creek in Glenn County, is owned by the U. S. Water and Power Resources Service. A 6 000-kilowatt hydroelectric power plant at this site could generate 18 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 30,700 barrels of oil in a fossil-fuel power plant.
(Photo by DWR Northern District, Red Bluff)

Camanche Dam, on the Mokelumne River in San Joaquin County, is owned by the East Bay Municipal Utility District. A 10 680-kilowatt hydroelectric power plant at this site could generate 35 million kilowatthours of electricity annually. This amount of energy is equivalent to burning 59,700 barrels of oil in a fossil-fuel power plant.
(East Bay Municipal Utility District Photo)

The CEC's most likely scenario in projecting the future cost of oil assumes that oil producers will continue to demand large price increases over the near term, and that new oil production and alternative derived fuels will only be developed at a moderate pace. The CEC's projected prices for oil and the projected annual escalation rates for these prices are shown in Tables 5 and 6, respectively.

Table 5. CEC's Projected Prices of Oil (1979 Dollars per Barrel)

Type of Oil	Year			
	1980	1985	1990	2000
Crude Oil	20.00	27.50	31.80	37.70
Distillate	25.58	38.00	43.85	51.56
Residual Oil (0.5% Sulfur)	22.87	35.82	42.00	49.67

Table 6. Annual Escalation Rates of Oil Prices (Percentage)

Type of Oil	Years		
	1981-85	1986-90	1990-2000
Crude Oil	6.6	3.0	1.7
Distillate	8.2	3.0	1.9
Residual Oil (0.5% Sulfur)	9.4	3.2	1.7

In order to assess the feasibility of a small hydroelectric project, the value of the energy generated during the early years of the project's operation must be determined. The economic benefits achieved during its first year of operation will likely increase in subsequent years due to increasing energy prices. Since the CEC's price projections were given in 1979 dollars. it is necessary to escalate those projections to reflect future inflated dollars. Estimates of general inflation rates are needed to determine these future oil prices, but projections of general inflation rates for future years are difficult to make.

It is logical to predict that the world price of oil will escalate as rapidly as the world economy can withstand it, until the price of oil approaches (but does not reach) the cost of producing synthetic fuels from coal, tar sands, and oil shale. If that level were reached, the price of oil would have to be competitive with that of alternative fuels.

Assuming that the world economy--and the American economy in particular--can withstand an annual inflation rate of about 12 percent, it is only a matter of time until synthetic fuels and solar energy <u>must</u> be developed. If the development of synthetic fuels and solar energy were ignored, the United States would have to pay a premium price for energy, and thereby, would become noncompetitive in the world market.

Given that synthetic fuels and solar electrical generation will be developed within five years, the logical scenario would show annual inflation rates of 15 percent in 1980, 12 percent in 1981 through 1985, 8 percent in 1986 through 1990, and 6 percent thereafter. Based on this and using the CEC median-price projections for basline data, the estimated price of oil in future dollars is shown in Table 7.

Table 7. Estimated Price of Oil (Future Dollars per Barrel)

Type of Oil	Year 1980	1985	1990	2000
Crude	23	54	94	193
Distillate	29	73	124	266
Residual Oil (0.5% Sulfur)	26	69	117	247

Residual Fuel Oil containing 0.5% sulfur is burned by PGandE to produce electrical energy. The projected 15 percent price increase 1980 would result in a 1980 cost of about $26 per barrel to PGandE. This is consistent with CECs projection and with the $26 price established by Saudi Arabia in mid-1980.

Estimated Payments for Hydroelectric Generation

The estimated payments for hydroelectric generation to be made by PGandE, SCE, and SDG&E are shown in Tables 8 and 9. The projections are based on estimated inflation and escalation rates, and the rates of proposed payments made by the utilities for hydroelectric generation in 1980. Since the payments for hydroelectric generation are based on the avoided cost of oil, the estimated price of oil is also shown in these tables. The historical and projected costs of oil burned by PGandE to produce electrical energy are shown in Figure 5.

Table 8. Projected Energy Rates for Sale of Small Hydroelectric Generation

Year	Oil Price Escalation Rate (%)1/	Inflation Rate (%)	Price of Oil ($/bbl)	Energy Rate (¢/kWh) PGandE	SCE	SDG&E
1980	-	15	26	5.1	4.6	5.4
1981	9.4	12	31	6.2	5.6	6.6
1982	9.4	12	38	7.5	6.8	8.0
1983	9.4	12	47	9.1	8.3	9.7
1984	9.4	12	57	11.1	10.1	11.7
1985	9.4	12	69	13.4	12.2	14.2
1986	3.2	8	77	15.0	13.6	15.8
1987	3.2	8	85	16.6	15.1	17.6
1988	3.2	8	95	18.5	16.8	19.6
1989	3.2	8	106	20.6	18.7	21.8
1990	3.2	8	117	22.9	20.8	24.2
1991	1.7	6	127	24.6	22.4	26.1
1992	1.7	6	136	26.5	24.1	28.1
1993	1.7	6	147	28.6	26.0	20.2
1994	1.7	6	158	30.8	28.0	32.6
1995	1.7	6	170	33.1	30.1	35.1
1996	1.7	6	184	35.7	32.5	37.8
1997	1.7	6	198	38.4	35.0	40.7
1998	1.7	6	213	41.4	37.7	43.8
1999	1.7	6	229	44.6	40.6	47.2
2000	1.7	6	247	48.0	43.7	50.8

1/California Energy Commission's Median Projection

Table 9. Capacity Payment Rates, by Utilities ($/kilowatt-year) Effective February 4, 1980.

Year of Initial Operation		Term of Sales (yrs)						
		1	5	10	15	20	25	30
1980	PGandE	-	56	62	68	73	-	81
	SCE	-	29	54	70	82	-	102
	SDG&E	-	-	16	27	35	40	-
1981	PGandE	-	60	66	72	77	-	85
	SCE	-	39	64	79	93	-	114
	SDG&E	-	-	22	34	43	48	-
1982	PGandE	-	63	69	75	81	-	89
	SCE	30	51	75	90	104	-	127
	SDG&E	-	8	30	43	52	59	-
1983	PGandE	60	66	73	79	85	-	94
	SCE	32	65	87	103	118	-	143
	SDG&E	-	18	41	54	64	71	-
1984	PGandE	63	69	76	83	89	-	98
	SCE	35	82	102	117	133	-	159
	SDG&E	-	30	53	67	78	86	-
1985	PGandE	66	73	80	87	93	-	103
	SCE	-	101	118	134	151	-	180
	SDG&E	-	45	68	83	95	104	-

Scotts Flat Dam, on Deer Creek in Nevada County, is owned by the Nevada Irrigation District. A 1 300-kilowatt hydroelectric power plant at this site could generate 5.5 million kilowatthours of electricity annually. This amount of energy would supply the annual electrical residential needs of 2,600 people.
(Photo by DWR Division of Safety of Dams)

Figure 5 Historical and Projected Average Cost of Oil for Electrical Generation at PG&E's Most Efficient Steam Electric Plants

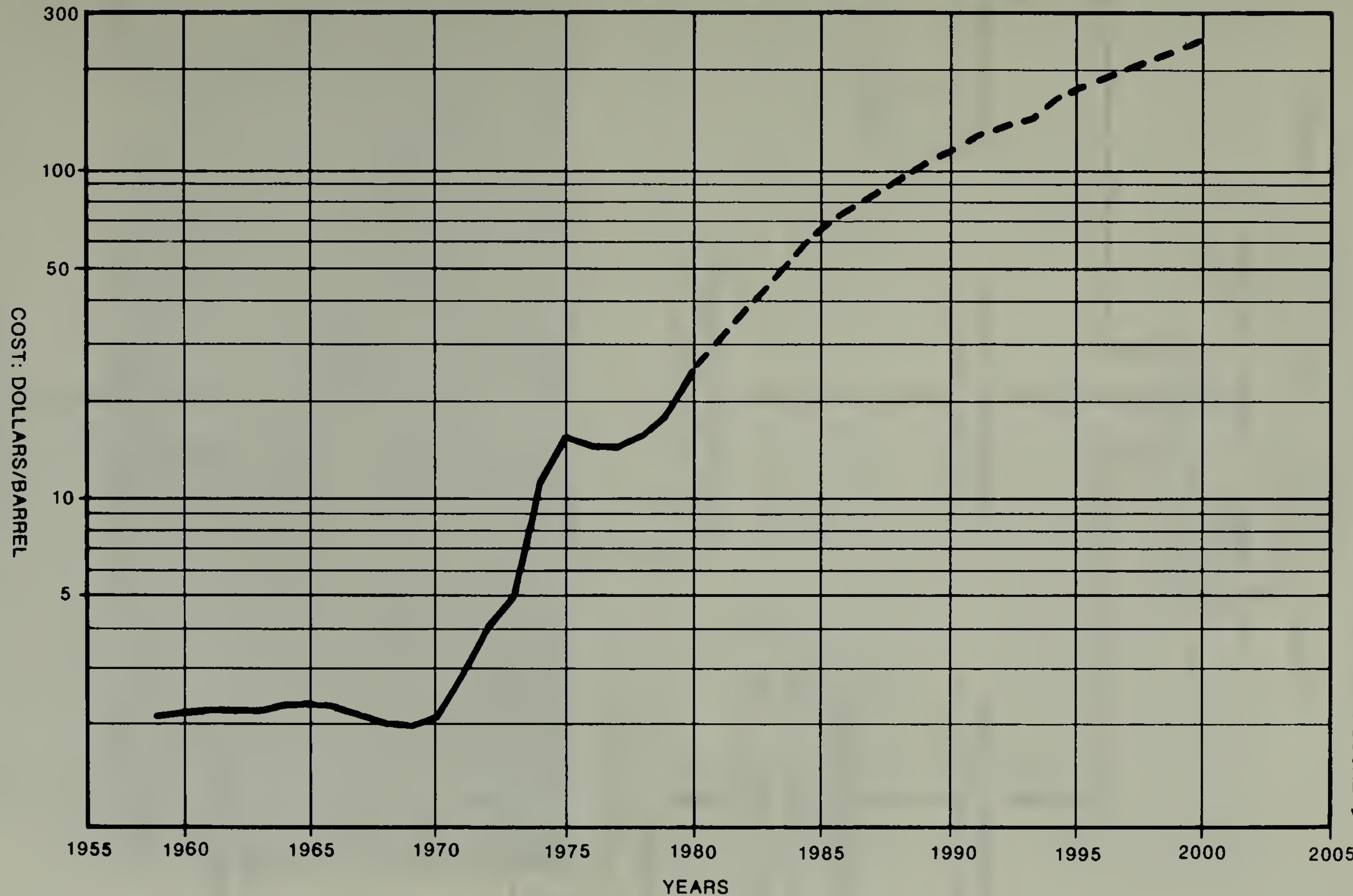
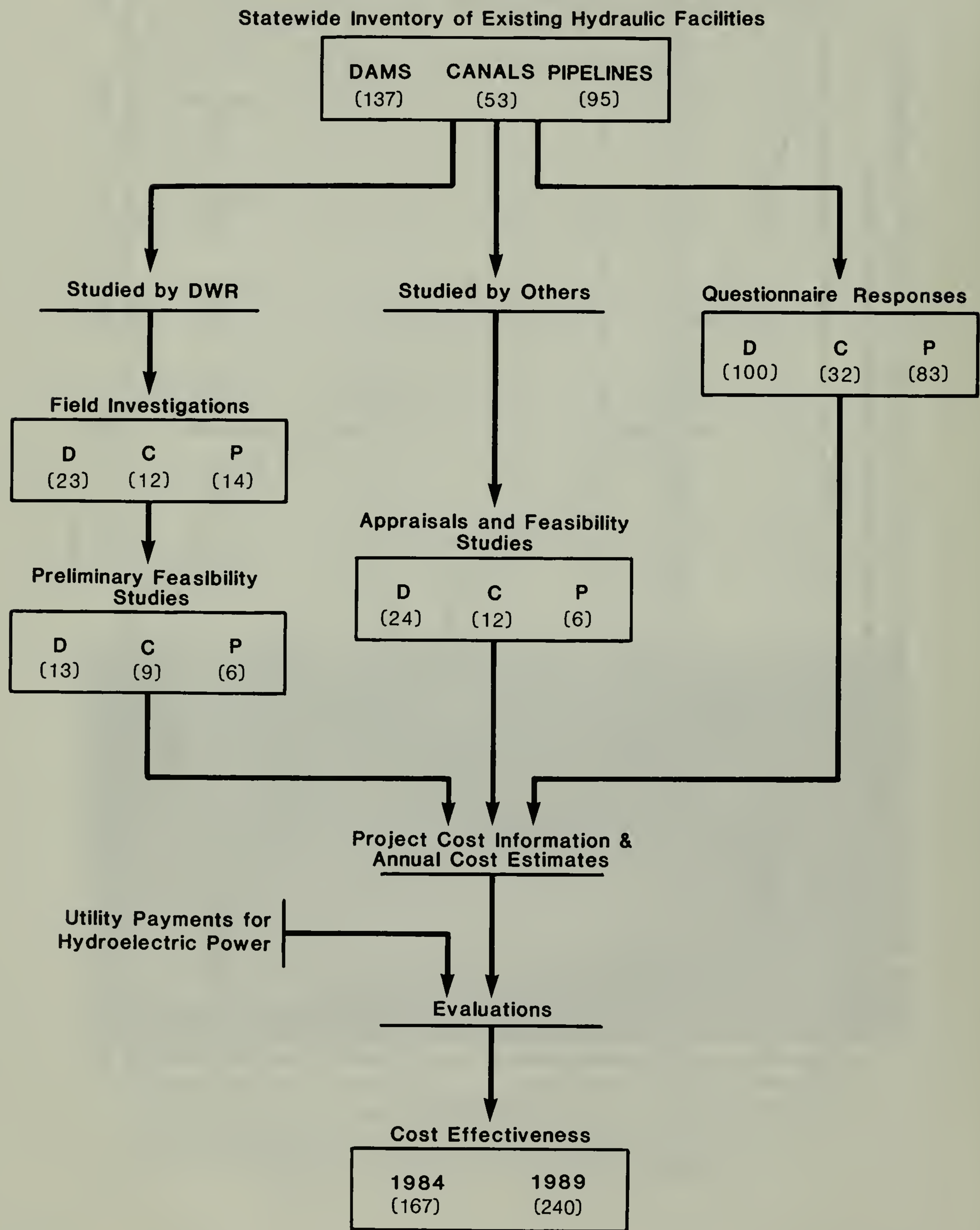


FIGURE 5

Figure 6 Selection and Evaluation Flow Chart



CHAPTER III

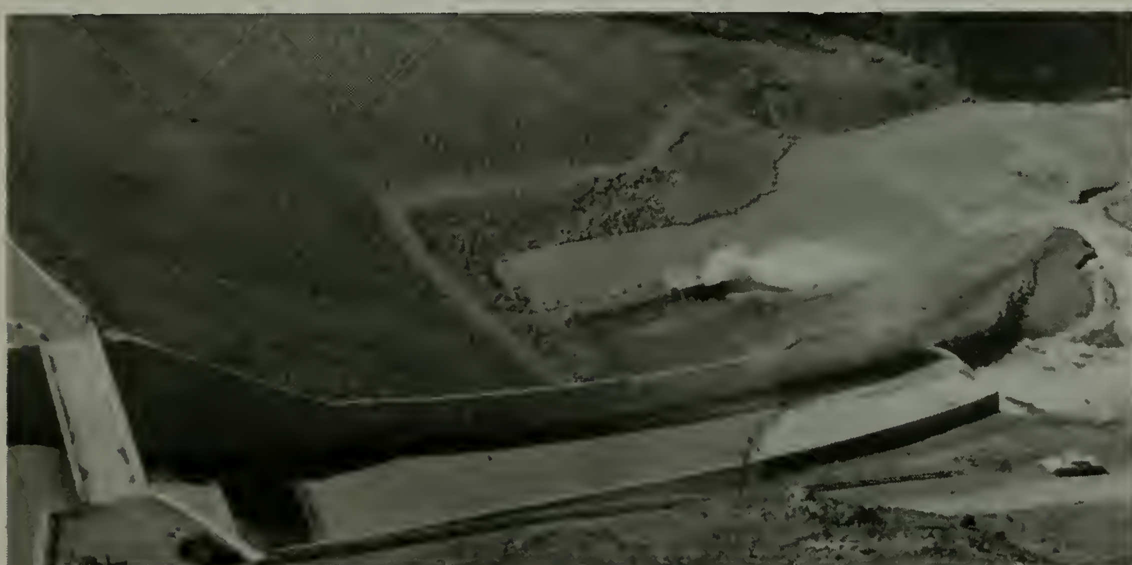
SELECTION AND EVALUATION

Hydraulic structures where hydroelectric facilities might be installed were identified through information obtained from (a) questionnaires distributed by the Department, (b) the U.S. Army Corps of Engineers' National Hydroelectric Power Study, (c) local water agencies and districts, and (d) the state's electric utilities. The Department identified 285 sites which had a potential for small hydroelectric development. These sites represented 510 000 kW of capacity and an annual output of 2.4 billion kWh of energy. The methodology for evaluating the cost effectiveness of each of the 285 sites is outlined in the Selection and Evaluation Flow Chart (Figure 6).

Selection

The facilities were divided into three groups based on the type of hydraulic structure: dam, canal, or pipeline. Each group was further divided into those facilities with installed capacities of 500 kW or greater and those with less than 500 kW of capacity. This was important for determining cost effectiveness since the cost of building a small power plant increases rapidly--on a dollar-per-kilowatt basis--as the installed capacity decreases below 500 kW.

Since time and money were limited, it was impossible to study each of the 285 facilities first hand. The evaluations made in this study were based on three types of information: data from preliminary feasibility studies conducted by the Department at 28 representative sites; data from



Ruth Reservoir (Robert W. Matthews Dam), on the Mad River in Trinity County, is owned by the Humboldt Bay Municipal Water District. A 1 600-kilowatt hydroelectric power plant at this site could generate 8.3 million kilowatthours of electricity per year. This is equivalent to burning 14,200 barrels of oil in a fossil-fuel power plant. (Photo by DWR Division of Safety of Dams) feasibility or appraisal studies conducted by others at 42 additional sites; and data on the head and flow at 215 remaining sites as obtained in response to the Department's questionnaries.

The Department conducted its studies in two phases consisting of field investigations and preliminary feasibility studies. Forty-nine sites were selected for initial field investigations. These sites represented the types of hydraulic structures found in California and contained examples from each of the six categories. The 49 facilities are listed in Table 10.

Table 10. Field Investigations Conducted by the Department of Water Resources

Site		Owner
1.	Anderson Flume Diversion1/	Anderson-Cottonwood Irrigation District
2.	Parkview Station1/	Anderson-Cottonwood Irrigation District
3.	Harding Canal1/	Browns Valley Irrigation District
4.	Merle Collins Reservoir1/ (Virginia Ranch Dam)	Browns Valley Irrigation District
5.	Frenchman Dam1/	California Department of Water Resources
6.	Beardsley Diversion1/	City of Bakersfield, et al.
7.	Rocky Point Diversion1/	City of Bakersfield, et al.
8.	Glendale Distribution1/	City of Glendale
9.	Alvarado Treatment Plant	City of San Diego
10.	Miramar Treatment Plant	City of San Diego
11.	Moccasin Reregulating Dam	City and County of San Francisco
12	Mount Olivette1/	City of Santa Monica
13.	Chowchilla Main Canal	Chowchilla Water District
14.	Fresno Main Canal	Fresno Irrigation District
15.	Gould Weir Diversion Dam1/	Fresno Irrigation District
16.	Del Loma Tunnel1/	George Costa
17.	Buckeye Conduit1/	Georgetown Divide Public Utility District
18.	Stumpy Meadows Reservoir1/ (Mark Edson Dam)	Georgetown Divide Public Utility District
19.	Ruth Reservoir (Robert W. Matthews Dam)	Humboldt Bay Municipal Water District
20.	Alamo Drop 3A1/	Imperial Irrigation District
21.	No. 8 Heading1/	Imperial Irrigation District
22.	Tuberose Check	Imperial Irrigation District
23.	Vail Heading1/	Imperial Irrigation District
24.	Lake Amador1/ (Jackson Creek Dam)	Jackson Valley Irrigation District
25.	Pacoima Dam	Los Angeles County Flood Control District
26.	San Gabriel Dam	Los Angeles County Flood Control District
27.	West Coast Basin Barrier1/	Los Angeles County Flood Control District

Table 10. Field Investigations Conducted by the Department of Water Resources (Continued)

Site	Owner
28. Eastside Pipeline	Lost Hills Water District
29. Lake Shastina[1/] (Shasta River Dam)	Montague Water Conservation District
30. Pumping Plant Lower[1/]	Montague Water Conservation District
31. Picay Pressure Break	Montecito County Water District
32. Lyons Dam	Pacific Gas and Electric Company
33. San Vicente Reservoir (Pipeline)	San Diego County Water Authority
34. Sidney N. Peterson Treatment Plant	San Juan Suburban Water District
35. Chesbro Dam[1/]	South Santa Clara Valley Water Conservation District
36. Uvas Dam[1/]	South Santa Clara Valley Water Conservation District
37. Black Butte Dam[1/]	U. S. Army Corps of Engineers
38. Hensley Lake (Hidden Dam)	U. S. Army Corps of Engineers
39. H.V. Eastman Lake (Buchanan Dam)	U. S. Army Corps of Engineers
40. Lake Kaweah (Terminus Dam)	U. S. Army Corps of Engineers
41. Lemoncove Ditch[1/] (At Terminus Dam)	U. S. Army Corps of Engineers
42. New Hogan Dam	U. S. Army Corps of Engineers
43. All-American Canal Drop No. 5	U. S. Water and Power Resources Service
44. Jenkinson Lake[1/] (Sly Park Dam)	U. S. Water and Power Resources Service
45. North Portal Tecolote[1/] Intake	Cachuma Operation and Maintenance Board
46. Stampede Dam	U. S. Water and Power Resources Service
47. Sonoma Reservoir	Valley of the Moon County Water District
48. Clear Lake Impounding[1/]	Yolo County Flood Control and Water Conservation District
49. Indian Valley Dam[1/]	Yolo County Flood Control and Water Conservation District

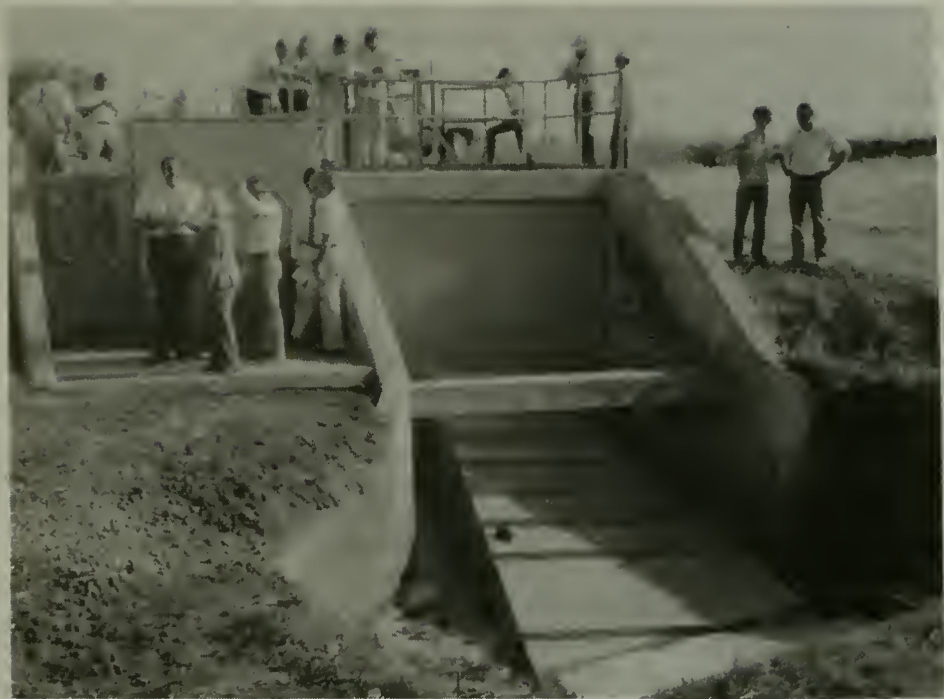
1/ Included in the 28 representative sites whose preliminary feasibility studies are presented in Appendix C.

Field Investigations

An on-site field study of each site was conducted to determine which sites were suitable for preliminary feasibility studies. During these inspections, the physical characteristics of the site were noted, including the amounts of head and flow, types of conduits and construction materials, the presence of canals and other adjoining waterways, and the characteristics of gates, valves, and energy dissipaters. The historical operational procedures and the primary purpose of the existing facility were also considered. A record of past flows and releases was obtained for use in computing the potential energy output. Each study is discussed briefly in Appendix B.

Some potential sites were unsuitable or impractical for development for various technical reasons. These included sites with (1) little or no effective head; (2) an inadequate combination of head and flow; (3) an adequate flow of limited duration; (4) concrete conduits that cannot be pressurized for use as penstocks; (5) a current use that is incompatible with hydroelectric generation; (6) serious environmental problems including those associated with development on a wild or scenic river or within a wilderness area; (7) a need for long transmission lines; or (8) hydraulic structures that are simply in poor physical condition.

Lake Pillsbury (Scott Dam), on the Eel River in Lake County, is owned by the Pacific Gas and Electric Company. A 2 800-kilowatt hydroelectric power plant at this site could generate 10 million kilowatthours of electricity per year. This amount of energy would supply the annual electrical residential needs of 3,400 people.
(Photo by DWR Energy Division)



Richvale Canal Powerplant, on the Richvale Canal in Butte County, is owned by the Richvale Irrigation District. This 100-kilowatt hydroelectric power plant, constructed in 1980, generates 0.4 million kilowatthours of electricity annually. This amount of energy will supply the annual electrical residential needs of 190 persons.
(Photo by DWR Energy Division)

Feasibility Studies

If the on-site inspection showed a power project to be technically feasible, economic feasibility and cost effectiveness could then be assessed on the basis of known site-specific characteristics. Of the 49 representative sites, projects at 28 of the sites were found to be technically feasible. These sites were then subjected to preliminary feasibility studies which used uniform methods to evaluate the physical layout, to estimate the necessary construction costs, and to provide a common base on which to develop guidelines for assessing other potential sites.

Guidelines

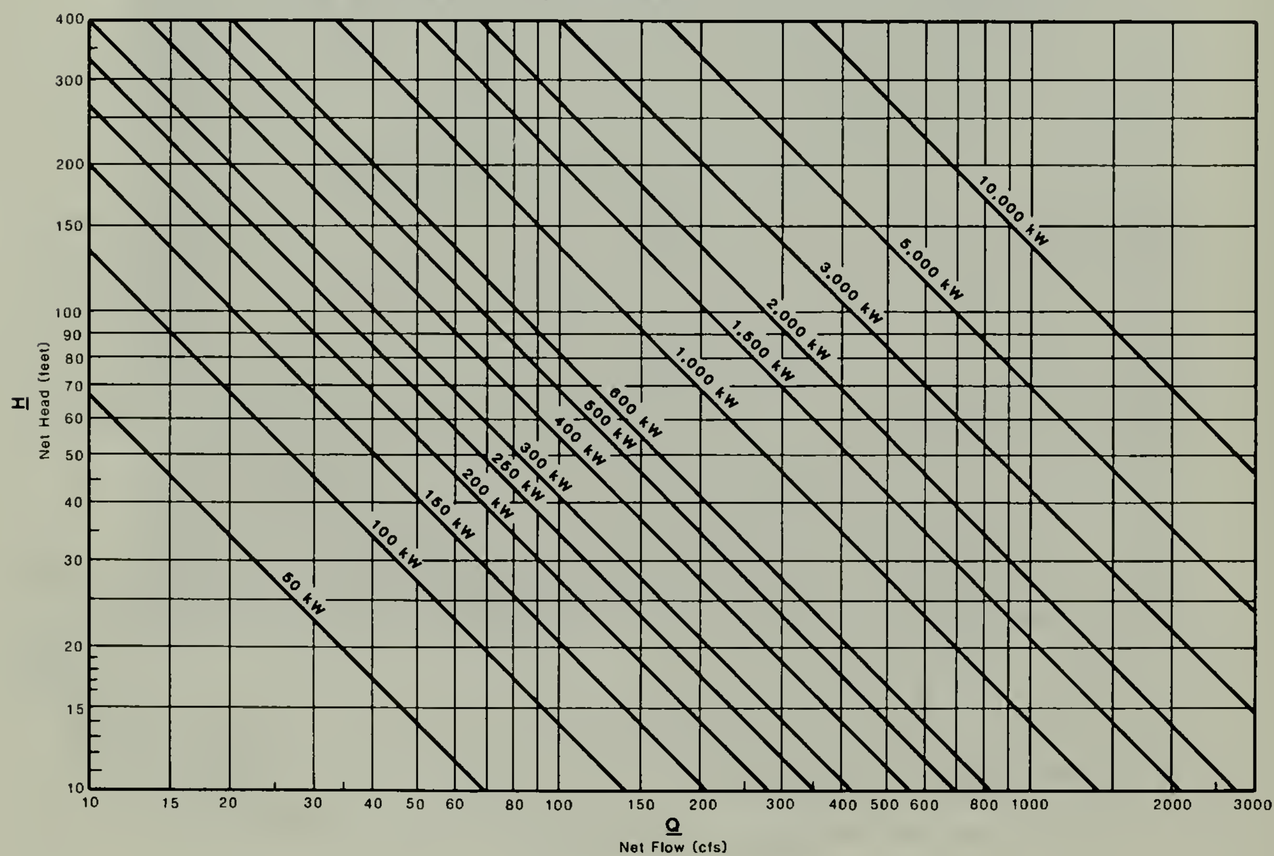
Each hydroelectric project is distinct, since few sites have the same combinations of head and flow or the same physical features. The most efficient turbine-generator design is one engineered specifically for the head and flow conditions of a particular site. The foundation, structures, and waterways must also be designed individually. If studies of specific hydroelectric sites are extrapolated to other sites which have unknown local conditions, a degree of error will be built-in to the evaluation.

Guidelines derived from a sampling of feasibility studies can be used to make a general assessment of other sites where the head and approximate annual flows are known. The guidelines based on the calculated cost effectiveness of the 28 representative sites studied by the Department were extrapolated to the 257 other sites. The parameters used included (1) Design capacity, as determined by the head and flow; (2) Annual energy generation, as determined from head and water available for power production; (3) Capacity factor; (4) Estimated project cost; (5) Estimated annual cost of ownership and operation; and (6) Payments by utilities for hydroelectric generation.

<u>Design Capacity</u>. The design capacity of a site is established by the physical features of the head and the flow of water. The design head is the net head after subtracting losses due to friction developed as the water flows to the turbine. However, since the known heads and flows at many potential sites are only approximations, the design head must be the estimated available head. The design flow, usually expressed in cubic feet per second (cfs) during a specific period of time such as a month, should be an average of more than three or four months.

The estimated capacity of the unknown site (C, in kilowatts), is the product of head (H, in feet) and flow (F, in cubic feet per second) divided by a factor that represents the efficiency of the equipment and the efficiency of converting the energy of falling water into electric power; for estimating purposes, an efficiency factor of 14 can be used. This results in the equation: $C = F \times H/14$ or $kW = cfs \times ft/14$. A graph of head and flow data can be used to estimate the design capacity of a site (Figure 7).

Figure 7 Power Developed at Various Combinations of Head and Flow



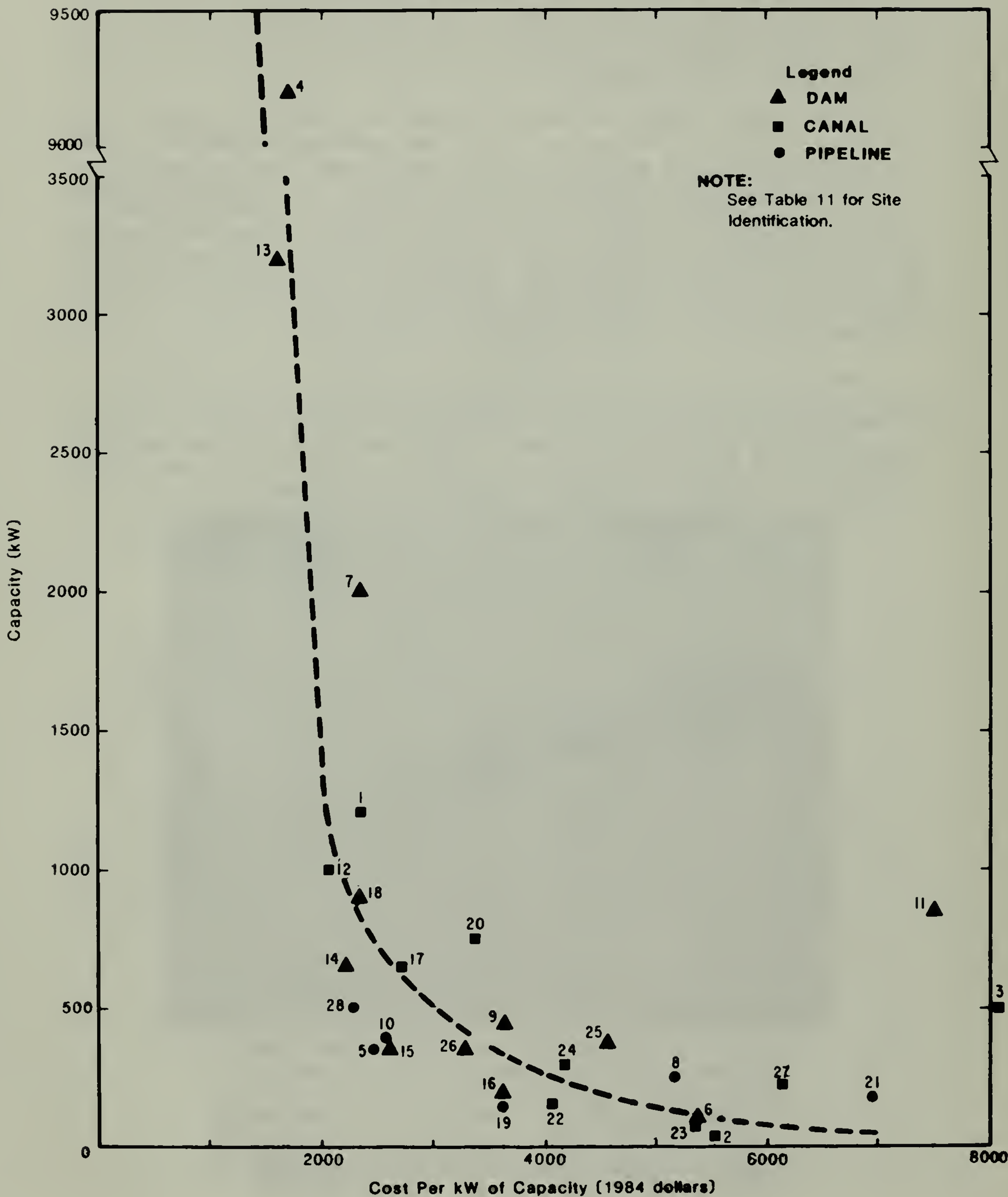
Project Cost. Among other things, the cost of constructing a hydroelectric project depends on local physical and geological features, and the length and size of the transmission lines required. The estimated cost of a particular facility is also affected by the design capacity. The estimated project costs for the 28 representative sites are shown in Figure 8 and are discussed in detail in Appendix C.

In the range of 50 kW to 3200 kW of installed capacity, project costs vary from $1,700 to $6,000 per kW. Since the costs were estimated in 1980 dollars for projects to be operational in 1984, these costs are escalated at 12 percent per year from January 1980 to obtain the January 1984 prices. The estimated costs include all direct costs such as studies, licensing, permits, and approvals, but do not include the indirect costs of financing and of interest during construction. Since the cost of interest during construction will vary depending on the interest rate charged on the funds which are available to the site developer, it has been included in the fixed annual cost of owning and operating the project.

The cost of constructing a project (in dollars per kW of installed capacity) increases rapidly for projects having capacities below 1000 kW. The estimated project cost ranges from $2,200 to $3,500 per kW for projects with capacities of 400 kW to 500 kW. From 200 kW to 400 kW, the cost increases to $3,500 to $4,500 per kW; and for projects of less than 200 kW, the project cost can be expected to exceed $4,500 per kW.

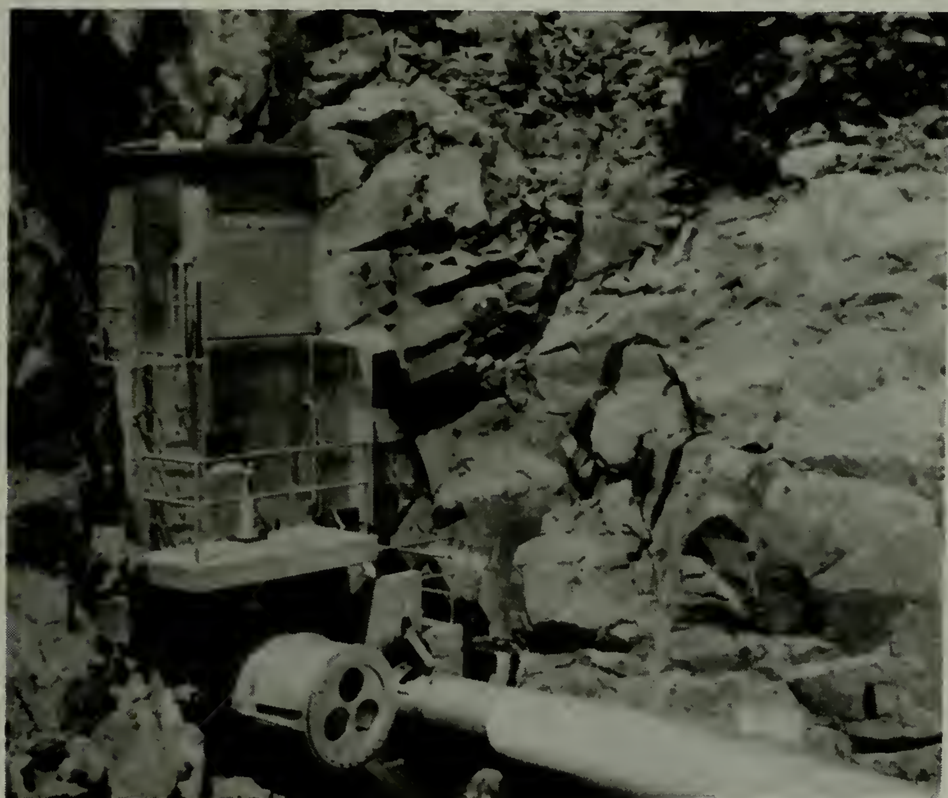
Black Butte Dam, on Stony Creek in Tehema County, is owned by the U. S. Army Corps of Engineers. A 9 200-kilowatt hydroelectric power plant at this site could generate 31.3 million kilowatthours of electricity per year. This amount of energy would supply the annual electrical residential needs of 14,900 people. (Photo by DWR Energy Division)

Figure 8 Estimated Costs of 28 Projects Studied by the Department of Water Resources



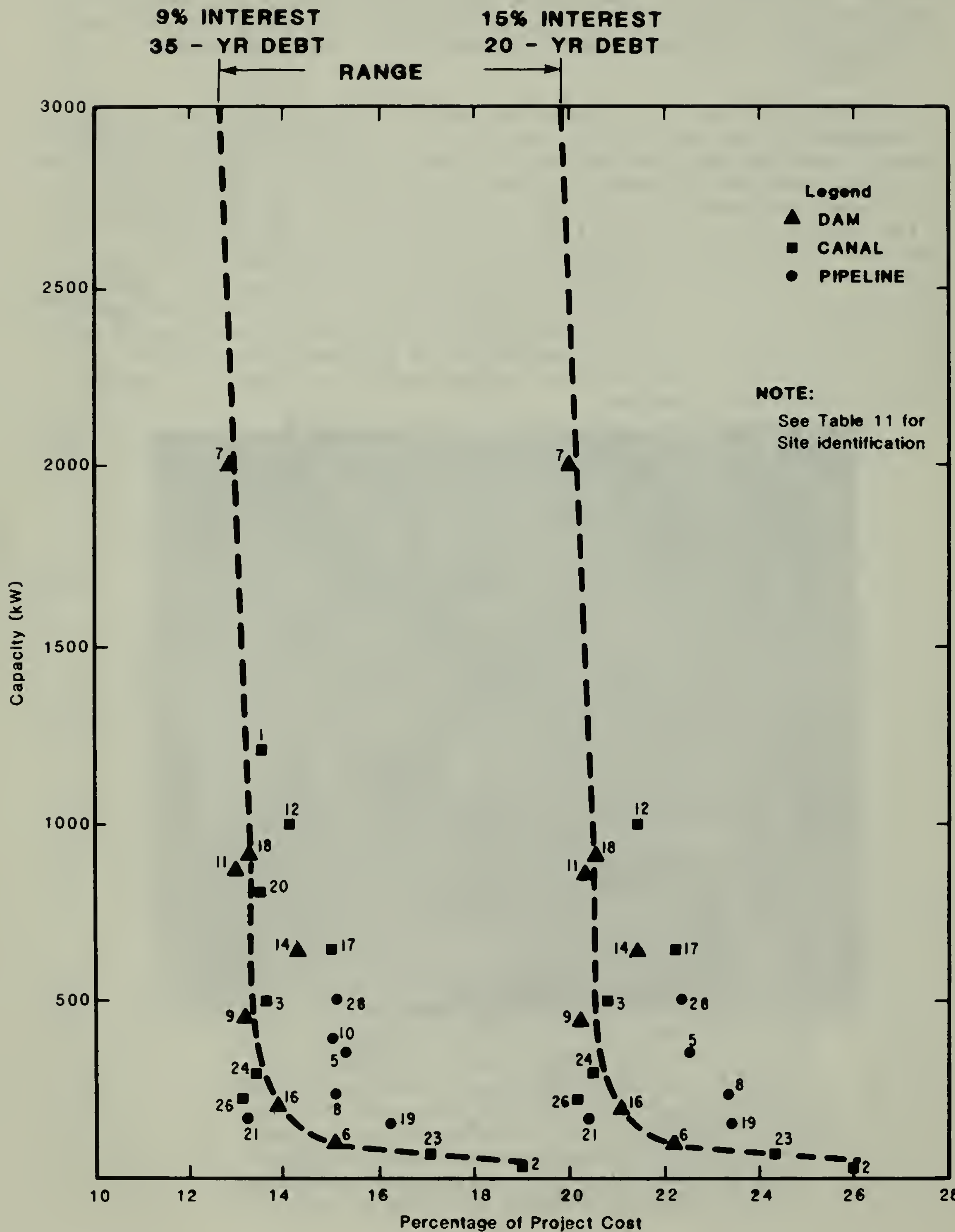
Annual Cost. The annual cost of owning and operating a hydroelectric project is principally debt payment, paying the interest and a portion of the borrowed principal. The remainder of the annual cost pays for operation and maintenance, insurance for the equipment, and the replacement of minor components that have shorter useful lives than the main generating facilities.

The interest rate for a long-term debt of 20 to 35 years has increased significantly since the third quarter of 1979. This reflects the current general American inflation and investor concern about the future rate of inflation. It is anticipated that the interest rate for hydroelectric development will continue at a high level for at least the next five years. Prior to the third quarter of 1979, the interest rate for tax-exempt bonds--as reflected by the Bond Buyer Index of 20 Bonds--was about 7 percent, and new, taxable utility bonds averaged 9.5 to 10 percent. From the third quarter of 1979 to mid-1980, the interest rate for tax-exempt bonds was about 9 percent, while that for taxable utility bonds was 12 to 13 percent. The interest rate for a loan of the $2 million to $10 million required for a small hydroelectric project could be as high as 15 percent under conventional financing.



Hell Hole Reservoir (Lower Hell Hole Dam), on the Rubicon River in Placer County, is owned by the Placer County Water Agency. A 400-kilowatt hydroelectric power plant at this site could generate 3 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 5,100 barrels of oil in a fossil-fuel power plant. (Photo by DWR Division of Safety of Dams)

Figure 9 Annual Cost of Owning and Operating Small Hydroelectric Projects



The financing of small hydroelectric projects is discussed in Appendix H and also shows how interest during construction and the cost of financing are included in the fixed annual costs. The range of total annual costs is fairly uniform at 13 to 21 percent of project costs for hydroelectric facilities with capacities of about 200 kW and greater (Figure 9). For hydroelectric facilities of less than 200 kW capacity, the annual costs increase significantly because a facility has basic maintenance and insurance costs regardless of its installed capacity.

Energy Generation. Besides the head, the annual energy output of a particular hydroelectric facility depends on the quantity of water that passes through its turbine. A hydroelectric installation at an irrigation structure would have flows available during the irrigation season from May through September, but there might not be any flow during other months of the year. Flood control dams, on the other hand, have normal release patterns during the winter and spring months.

Energy generation (kWh) is equal to the average number of kilowatts (kW)--calculated from the head and average flow in the same manner as for design capacity--times the number of hours that the head and flow are available. These calculations for the 28 selected sites are discussed in Appendix C and provide the guidelines for calculating energy generation at other facilities.

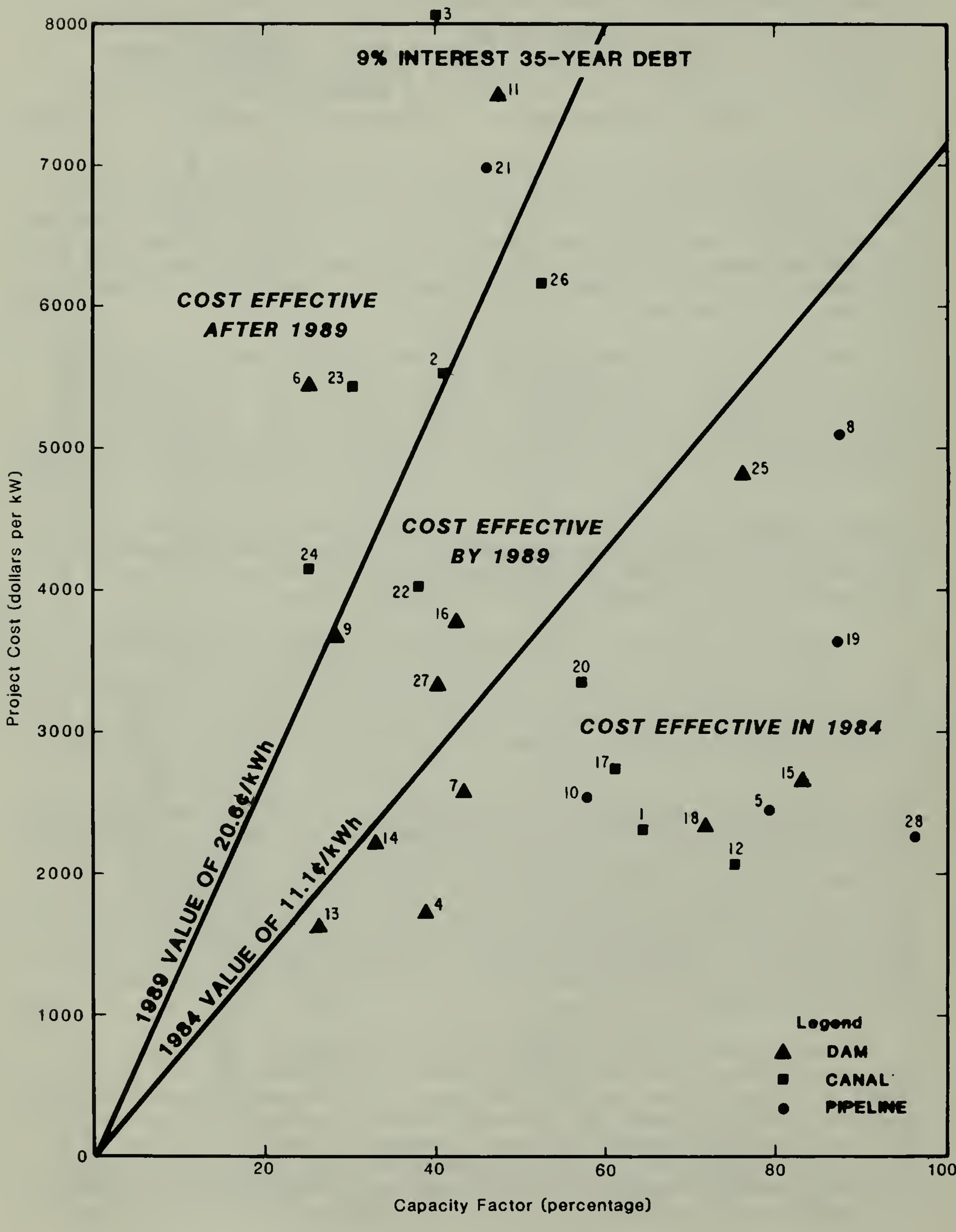
Capacity Factor. The capacity factor of a hydroelectric installation is the ratio of the energy generated (kWh) to the total amount of energy that would be produced if the facility could operate at its design capacity throughout the period being considered, usually a year.

Capacity factors for the 28 preliminary feasibility studies ranged between 25 and 90 percent; most sites fell in the range of 40 to 60 percent. Pipeline installations usually showed higher capacity factors because distribution systems usually operate most of the year. The capacity factor is a useful, common base for evaluating the relationship between the cost and the value (revenues from sales) of generation.

Utility Payments for Hydroelectric Generation. The value of generation is the price a purchaser would pay for the capacity and energy produced by a project. This is discussed in detail in Chapter II and Appendix G. In mid-1980, the price PGandE would pay for cogeneration averaged about 6.1 cents per kWh, and PGandE's proposed policy for pricing hydroelectric generation averaged about 4.0 to 4.2 cents per kWh. Southern California Edison Company's (SCE) published price averaged about 5.1 cents per kWh, and San Diego Gas and Electric Company's (SDG&E) price averaged about 5.9 cents per kWh.

These prices escalate along with the price of oil. Using the California Energy Commission's (CEC) median price projection for future oil and a 12 percent inflation rate, the value of hydroelectric energy in 1984 would be about 11.1 cents per kWh under PGandE's cogeneration rate and 8.7 cents per kWh under its proposed hydroelectric rate. The value of capacity, if applicable, would be in addition to the value of energy for a total of about 12.3 cents per kWh for cogeneration and 8.9 cents per kWh for hydroelectric generation in 1984. The comparable SCE value for 1984

Figure 10 Preliminary Assessment of 28 Sites Studied by the Department of Water Resources



would be 10.1 cents per kWh for energy plus about 1 cent for capacity, and SDGandE's value would be 11.7 cents for energy plus about 1.3 cents for capacity. The values estimated for other years are shown in Table 8, Chapter II. To estimate the number of sites that are cost effective, the price that utilities would pay for hydroelectric generation was assumed to be 11.1 cents per kWh in 1984 and 20.6 cents per kWh in 1989.

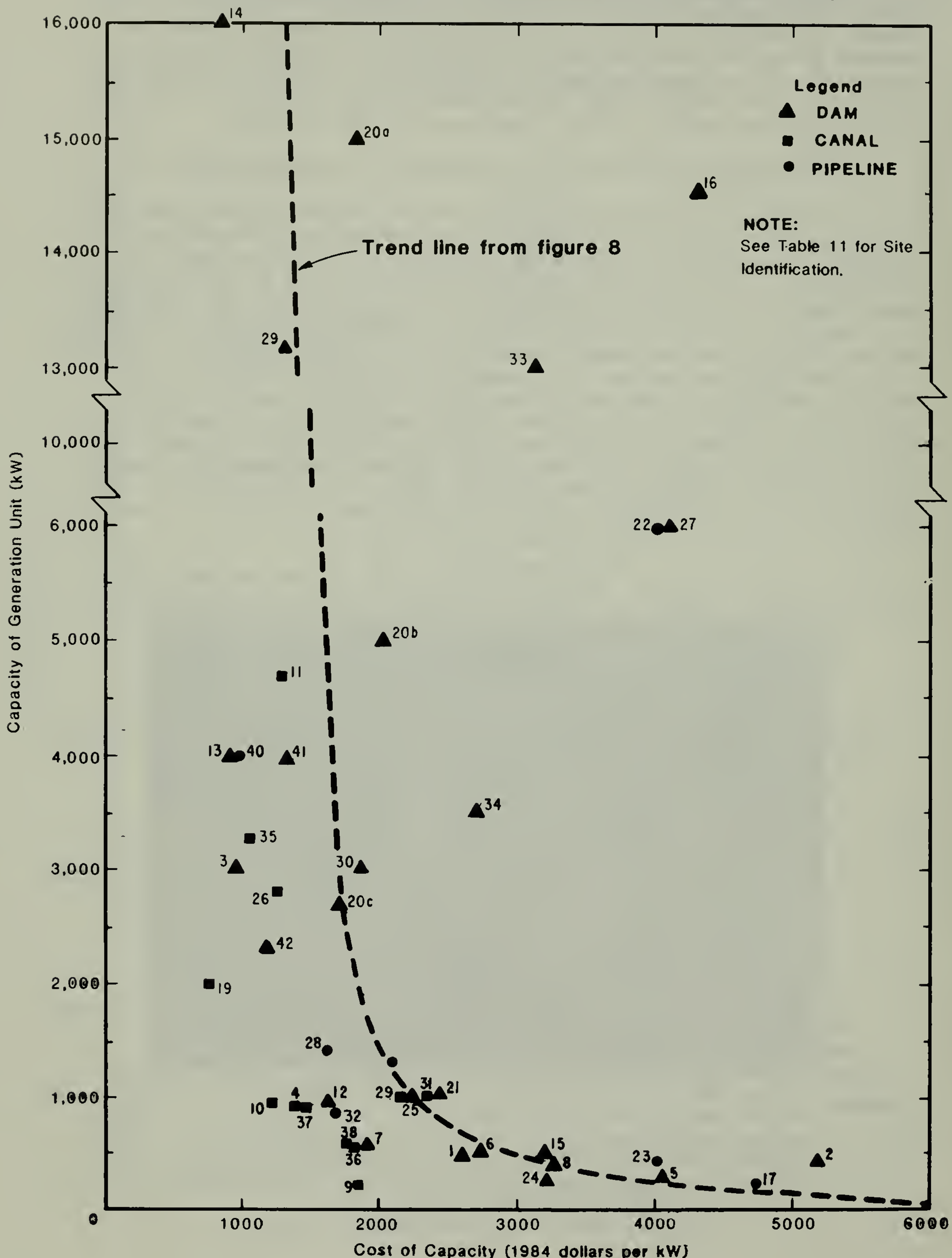
Assessment of 28 Sites by the Department of Water Resources

According to the rates published by PGandE, SDG&E, and SCE, the value of hydroelectric generation is primarily the energy value because the avoided costs are based on oil-fired generation. The average value of hydroelectric generation--the published price that would be paid for such generation--can be expressed as the break-even project cost of a hydroelectric facility. The break-even point is reached when the annual cost of owning and operating the project equals the revenues received from the sale of the project's generation. For example, the break-even cost for a project financed at 12 percent interest for 20 years (resulting in an annual cost of 19 percent of project cost), operating at a 50 percent capacity factor, and an energy value of 11.1 cents per kWh, is equal to ($0.111 x 0.5 x 8760/0.19) or about $2560 per kW. The break-even costs will be different with different interest rates, terms of financing, and energy values. The allowable project cost is directly related to capacity factor.

The relative economic feasibility of each of the 28 representative sites is shown in Figure 10. The sloped lines represent the break-even

Combie Dam, on the Bear River in Nevada County, is owned by the Nevada Irrigation District. A 1 000-kilowatt hydroelectric power plant at this site could generate 4 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 6,800 barrels of oil in a fossil-fuel power plant.
(Photo by DWR Division of Safety of Dams)

Figure 11 Estimated Project Costs For 42 Sites Studied by Others



project costs for a 9 percent interest rate and a 35-year term of debt, assuming the energy value is 11.1 cents per kWh in 1984 and 20.6 cents in 1989. The numbers and symbols represent facilities and correspond to the sequence used for identifying the 28 sites listed in Table 11 and discussed in Appendix C.

Sixteen of the 28 facilities would be cost effective in 1984, and represent a total installed capacity of 21 875 kW and an annual energy generation of 91 million kWh. Five additional sites would be cost effective by 1989; the remaining 7 sites would not prove cost effective under current fuel cost projections.

The cost of generation at each of the 28 sites is tabulated in cents per kWh in Table 11.

Assessment of 42 Sites by Others

The studies prepared by others vary in scope from preliminary assessments to full-fledged feasibility studies. Because the studies were prepared at different times by different engineering firms or by owners, there is no common basis for estimating costs. For these reasons, the results presented here should be used only as an indication of cost effectiveness. The estimated project costs of the 42 sites, are presented in Figure 11. The numbers and symbols represent facilities and correspond to the sequence used for identifying the 42 sites listed in Table 11 and discussed in Appendix D. The dashed trend line shown in the figure was developed from data collected during the 28 studies prepared by the Department.

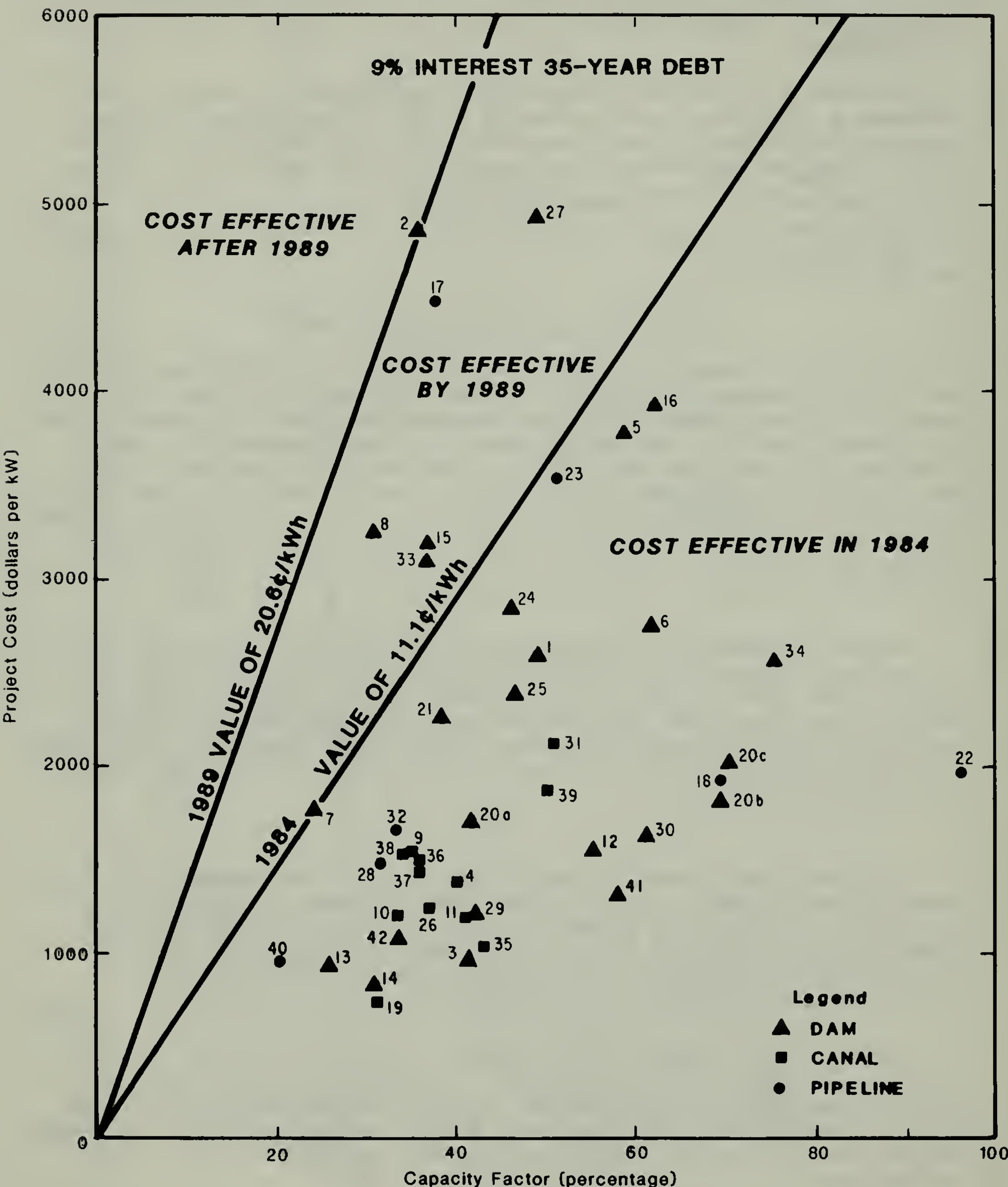
Before assessing the economic feasibility of the 42 facilities, the project costs presented in the reports were increased at 12 percent annually to cover inflation to 1984. The annual cost of owning and operating each proposed power plant was also estimated based on the information developed in the Department's studies. These annual costs (as a percentage of the project costs) are given for a range of interest rates and terms of debt service (Figure 9).

The cost effectiveness of each of the 42 sites was estimated by comparing annual costs to the expected annual revenue from project generation. The relative economic feasibility of each of the 42 sites, based on energy values of 11.1 cents per kWh in 1984 and 20.6 cents in 1989, is shown in Figure 12. The break-even costs are shown for an interest rate of 9 percent and a 35-year term of debt.

Based on the estimated energy value of 11.1 cents per kWh, 36 of the 42 facilities would be cost effective in 1984. They represent a total installed capacity of 134 135 kW and an annual generation of 610 million kWh. Five additional facilities would be cost effective by 1989; only one facility would not prove cost effective under current fuel cost projections.

The cost of generation at each of the 42 sites is tabulated in cents per kWh in Table 11.

Figure12 Preliminary Assessment of 42 Sites Studied by Others



Assessment of 215 Sites From Data on Questionnaires

The Department's questionnaires provided sufficient information to estimate the installed capacity, energy generation, and capacity factor for 215 sites. The head and flow data from the questionnaires are assumed to be approximations and, in many instances, may be optimistic estimates of the resource.

Although these 215 sites may be suitable for power development, on-site inspections by qualified engineers, and refined head and flow data are needed before their cost effectiveness as small hydroelectric developments can be confirmed. To estimate their cost effectiveness, the cost information developed from the Department's 28 feasibility studies was used as a basis. The cost in dollars per kW, based on the estimated installed capacity, was obtained from Figure 8. The annual cost of owning and operating each site was then estimated from Figure 9.

At an interest rate of 9 percent, a 35-year debt repayment period, and an energy value of 11.1 cents per kWh, 115 sites would be cost effective in 1984; they represent a total installed capacity of 311 290 kW and an annual generation of 1.5 billion kWh. An additional 63 sites would be cost effective by 1989; 37 sites would not prove cost effective under current fuel cost projections.

The cost of generation for each of the 215 sites is tabulated in cents per kWh in Table 11.

Summary of Assessment

The estimates of the economic feasibility of the 285 potential hydroelectric sites at existing facilities were based on several factors:

(1) Cost data developed from the Department's preliminary feasibility studies of 28 sites;

(2) The estimated cost and estimated annual generation at 42 sites studied by others;

(3) The estimated capacity and estimated energy generated at 215 sites whose information was obtained from questionnaires;

(4) A 35-year debt at an assumed interest rate of 9 percent; and

(5) Estimated payment by utilities for hydroelectric generation of 11.1 cents per kWh in 1984, and 20.6 cents in 1989.

To determine the number of power plants that would be cost effective in 1989, it was assumed that these power plants would be constructed and on line by 1984, and that the developer would operate the power plant at a loss for the first one to five years.

Based on these conditions and assumptions the cost effectiveness of small hydroelectric development at 285 existing facilities in California are listed in Table 11 and summarized in Table 12, and Figure 1.

Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
	FACILITIES STUDIED BY DEPARTMENT OF WATER RESOURCES					
1. Alamo Drop 3A (Canal)	Imperial Irrigation District	2	1 200	6.7	2,312	6.4
2. Anderson Flume Diversion (Canal)	Anderson-Cottonwood Irrigation District	2	50	0.2	5,518	28.5
3. Beardsley Diversion Structure (Canal)	City of Bakersfield, et al	2	500	1.7	8,062	31.5
4. Black Butte Dam	U. S. Army Corps of Engineers	2,4	9 200	31.3	1,717	6.4
5. Buckeye Conduit	Georgetown Divide Public Utility District	2	350	2.4	2,451	5.4
Carrier Canal Project	(See Rocky Point Diversion Dam)					
6. Chesbro Reservoir (Elmer J. Chesbro Dam)	South Santa Clara Valley Water and Conservation District	2	100	0.2	5,343	36.8
7. Clear Lake Impounding Dam	Yolo County Flood Control and Water Conservation District	2	2 000	7.5	2,469	8.2
8. Del Loma Tunnel	George Costa	2,3	250	1.9	5,138	10.2
Elmer J. Chesbro Dam	(See Chesbro Reservoir)					
9. Frenchman Dam	California Department of Water Resources	2	450	1.0	3,657	20.0
10. Glendale Distribution System (Pipeline)	City of Glendale	2	400	2.0	2,558	6.9
11. Gould Weir Diversion Dam	Fresno Irrigation District	2	850	3.5	7,499	23.7
12. Harding Canal	Browns Valley Irrigation District	2,4	1 000	6.6	2,077	4.5
13. Indian Valley Dam	Yolo County Flood Control and Water Conservation District	2	3 200	7.2	1,648	10.5
14. Jenkinson Lake (Sly Park Dam)	U. S. Water and Power Resources Service	2,3	650	1.8	2,208	10.9
15. Lake Amador (Jackson Creek Dam)	Jackson Valley Irrigation District	2	350	2.5	2,631	5.1
16. Lake Shastina (Shasta River Dam)	Montague Water Conservation District	2	200	0.7	3,608	13.4
17. Lemoncove Ditch (At Terminus Dam)	U. S. Army Corps of Engineers	2	650	3.5	2,754	7.7
Mark Edson Dam	(See Stumpy Meadows Reservoir)					
18. Merle Collins Reservoir (Virginia Ranch Dam)	Brown Valley Irrigation District	2,4	900	5.6	2,314	4.9

1. Status Unknown
2. Appraisal or Feasibility Study Completed
3. Application Filed for FERC Preliminary Permit
4. FERC Preliminary Permit Issued
5. Application Filed for FERC Exemption or License
6. FERC Exemption or License Issued
7. Under Construction
8. Insufficient Data Received

Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
19. Mount Olivette (Pipeline)	City of Santa Monica	2	150	1.1	3,646	7.9
20. No. 8 Heading (Canal)	Imperial Irrigation District	2	750	3.9	3,362	10.0
21. North Portal Tecolote Tunnel	U. S. Water and Power Resources Service	2	175	0.7	6,993	22.4
22. Parkview Station (Canal)	Anderson-Cottonwood Irrigation District	2	150	0.5	4,030	15.8
23. Pumping Plant Lower (Canal)	Montague Water Conservation District	2	65	0.2	5,331	34.4
24. Rocky Point Diversion Structure (Carrier Canal Project)	City of Bakersfield, et al	2,3	300	0.7	4,150	24.8
Sly Park Dam	(See Jenkinson Lake)					
25. Stumpy Meadows Reservoir (Mark Edson Dam)	Georgetown Divide Public Utility District	2	325	2.2	4,652	8.5
26. Uvas Dam	South Santa Clara Valley Water Conservation District	2	300	1.0	3,267	13.1
27. Vail Heading (Canal)	Imperial Irrigation District	2	225	1.0	6,167	17.8
28. West Coast Basin Barrier (Pipeline)	Los Angeles County Flood Control District	2	500	4.2	2,270	4.1
	FACILITIES STUDIED BY OTHERS					
ACID Diversion Dam	(See Lake Redding)					
1. Anderson Lake (Leroy Anderson Dam)	Santa Clara Valley Water District	2	500	2.2	2,610	8.0
2. Antelope Dam	California Department of Water Resources	2	450	1.4	5,200	22.8
3. Bowman Dam	Nevada Irrigation District	2	3 000	14.7	1,080	2.7
4. Canal Creek	Merced Irrigation District	2,6	940	3.3	1,540	5.7
Canal Drop No. 1,2,6,7, and 9	(See Turlock Main Canal)					
5. Castaic Outlet (Dam)	California Department of Water Resources	2	275	1.4	4,030	10.7
6. Combie Dam	Nevada Irrigation District	2,4	525	2.9	3,060	7.5
7. Coyote Dam	Santa Clara Valley Water District	2	600	1.3	1,990	12.4
8. Del Valle Stream Release (Dam)	California Department of Water Resources	2	400	1.1	3,450	16.9
9. Escaladian Headworks (Canal)	Merced Irrigation District	2,6	270	0.8	1,870	8.3

See footnotes on first page

Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
10. Fairfield Drop (Canal)	Merced Irrigation District	2,6	970	2.8	1,380	6.3
11. Frankenheimer Drop (Canal)	South San Joaquin Irrigation District	2,5	4 700	17.0	1,320	4.4
Friant Dam	(See Millerton Lake)					
12. Goodwin Dam	Oakdale and South San Joaquin Irrigation District	2	970	4.7	1,710	4.6
Grizzly Valley Dam	(See Lake Davis)					
13. Jackson Meadows Dam	Nevada Irrigation District	2	4 000	8.9	1,010	5.4
14. Lake Berryessa (Monticello Dam)	U. S. Water and Power Resources Service	2,5	16 000	43.0	920	4.1
15. Lake Davis (Grizzly Valley Dam)	California Department of Water Resources	2	510	1.5	3,380	15.5
16. Lake Redding (ACID Diversion Dam)	Anderson-Cottonwood Irrigation District	2,4	14 500	79.0	4,390	9.7
17. Las Flores Turnout (Pipeline)	California Department of Water Resources	2	210	0.7	4,750	20.0
Leroy Anderson Dam	(See Anderson Lake)					
18. Lytle Creek Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	1 300	7.8	2,130	4.6
19. Madera Canal Station 980+65	U. S. Water and Power Resources Service	2	2 000	5.5	840	3.8
20. Millerton Lake (Friant Dam)						
(a) Friant-Kern Canal	U. S. Water and Power Resources Service	2,4	15 000	90.3	1,860	3.7
(b) Madera Canal	U. S. Water and Power Resources Service	2,4	5 000	30.6	2,050	4.0
(c) San Joaquin River)	U. S. Water and Power Resources Service	2,4	2 700	9.9	1,750	5.9
21. Modesto Reservoir (Dam)	Modesto Irrigation District	2	1 000	3.4	2,510	9.6
22. Mojave Siphon No. 1 (Silverwood Lake Inlet, Pipeline)	California Department of Water Resources	2	6 000	47.0	4,029	6.2
Monticello Dam	(See Lake Berryessa)					
23. Palermo Canal Release	California Department of Water Resources	2	400	1.5	4,023	14.5
24. Paradise Dam	Paradise Irrigation District	2	300	1.2	3,160	10.7
25. Pyramid Stream Release (Dam)	California Department of Water Resources	2	1 000	3.2	2,208	9.0
26. Richard B. Parker (On Main Canal)	Merced Irrigation District	2,6	2 800	9.2	1,400	5.4
27. San Antonio Dam	Monterey County Flood Control and Water Conservation District	2,4	6 000	25.6	4,200	11.8

See footnotes on first page

Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
28. Santa Ana Low Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	1 400	3.8	1,660	8.0
29. Sly Creek Dam	Oroville-Wyandotte Irrigation District	2,5	13 200	48.2	1,360	4.5
30. Stampede Dam	U. S. Water and Power Resources Service	2	3 000	16.0	1,820	4.3
31. Stone Drop (Canal)	Modesto Irrigation District	2	1 000	4.0	2,390	9.6
32. Sweetwater Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	875	2.2	1,840	9.5
33. Thermalito Afterbay River Outlet (Dam)	California Department of Water Resources	2,6	13 000	42.6	3,290	12.1
34. Thermalito Diversion Dam	California Department of Water Resources	2,6	3 500	23.0	2,700	5.1
35. Turlock Main Canal Drop No. 1	Turlock Irrigation District	7	3 260	12.2	1,170	3.7
36. Turlock Main Canal Drop No. 2	Turlock Irrigation District	2	660	2.1	1,800	7.6
37. Turlock Main Canal Drop No. 6	Turlock Irrigation District	2,5	920	2.9	1,620	6.7
38. Turlock Main Canal Drop No. 7	Turlock Irrigation District	2	700	2.1	1,770	8.0
39. Turlock Main Canal Drop No. 9	Turlock Irrigation District	7	1 070	4.7	2,090	6.2
40. Waterman Canyon Turnout (Pipeline)	San Bernardino Valley Municipal Water District	2,4	4 000	7.0	1,090	7.5
41. Whiskeytown Dam	U. S. Water and Power Resources Service	2,4	4 000	19.5	1,460	3.6
42. Woodward Dam	South San Joaquin Irrigation District	2,6	2,300	6.9	1,210	5.0

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
	FACILITIES EVALUATED FROM QUESTIONNAIRES					
Alamitos Barrier (Dam)	Los Angeles County Flood Control District	1	300	1.0	3,900	15.8
Alisal Creek Dam	Petan Company	1	50	0.2	5,600	27.3
All-American Canal Drop No. 1	U. S. Water and Power Resources Service	2	4 700	27.0	1,600	3.3
All-American Canal Drop No. 5	U. S. Water and Power Resources Service	2	5 000	24.0	1,600	4.0
Alvarado Treatment Plant (Pipeline)	City of San Diego	2	1 700	8.4	1,950	5.1
Anthony House Dam	Lake Wildwood Association	1	50	0.2	5,600	27.3
Ash Main Canal	Chowchilla Water District	1	150	0.7	4,950	14.9
Azusa Flow Control Structure (Pipeline)	San Gabriel Valley Municipal Water District	2	740	3.2	2,550	8.0
Balboa (Pipeline)	Metropolitan Water District of Southern California	2,5	1 200	9.1	2,050	3.5
Barrett Dam	City of San Diego	1	60	0.2	5,600	32.8
Beardsley Canal Control Structure	City of Bakersfield, et al	3	260	1.1	4,200	13.4
Bear Valley Powerplant (Rehabilitation)	Escondido Mutual Water Company	2,5	700	3.7	2,600	6.6
Benson Feeder Pipeline	Monte Vista County Water District	1	8/	8/	--	--
Big Creek Hydroelectric Plant (Rehabilitation)	Lockheed Missles and Space Company, Inc.	2	800	3.0	2,450	8.8
Big Dalton Dam	Los Angeles County Flood Control District	1	50	0.1	5,600	53.2
Big Dalton Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal Water District	2	280	1.2	4,150	13.1
Big Sage Dam	Hot Springs Valley Irrigation District	1	175	0.7	4,700	16.5
Big Tujunga No. 1 Dam	Los Angeles County Flood Control District	1	300	1.3	3,900	12.2
Boca Dam	U. S. Water and Power Resources Service	2,4	2 000	5.6	1,900	8.5
Box Canyon Dam	(See Lake Siskiyou)					
Buhach (Canal)	Merced Irrigation District	1	60	0.3	5,600	21.8
Buchanan Dam	(See H.V. Eastman Lake)					

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Bucks Lake (Bucks Storage Dam)	Pacific Gas and Electric Company	1	740	3.2	2,550	8.0
Bucks Storage Dam	(See Bucks Lake)					
Buffalo Hill Siphon (Pipeline)	Georgetown Divide Public Utility District	1	160	0.5	4,950	22.2
Buhach Drop (Canal)	Merced Irrigation District	1	60	0.3	5,600	21.8
Cache Slough (Pipeline)	City of Vallejo	1	600	4.1	2,850	5.6
Calaveras Dam	City and County of San Francisco	1	700	3.2	2,600	7.7
Calero Dam	Santa Clara Valley Water District	1	100	0.5	5,450	16.4
Califa Canal	Chowchilla Water District	1	200	0.9	4,500	14.0
Camanche Dam (Lower Mokelumne River Project)	East Bay Municipal Utility District	5	10 680	35.0	1,500	5.5
Camp Far West Dam	South Sutter Water District	5	6 800	26.9	1,550	4.7
Cardinal Power House	Southern California Edison Company		2 500	10.3	1,800	5.5
Carneros Power Project (Pipeline)	Goleta County Water District	1	700	1.6	2,600	15.4
Casitas Dam	U. S. Water and Power Resources Service	1	700	2.0	2,600	12.3
Central Amador Water Project	Amador County Water Agency	2	250	0.7	4,200	20.3
Ceres Spillway (Canal)	Turlock Irrigation District	1	2 100	4.5	1,850	10.8
Chowchilla Main Canal						
Station 0+00	Chowchilla Water District	2	250	1.1	4,200	12.9
Station 101+80	Chowchilla Water District	2	250	1.1	4,200	12.9
Station 175+00	Chowchilla Water District	2	250	1.1	4,200	12.9
City Creek Turnout (Pipeline)	San Bernardino Valley Municipal Water District	1	2 000	3.0	1,900	15.8
Clear Lake Dam	U. S. Water and Power Resources Service	1	430	1.9	3,350	10.2
Cogswell Dam	Los Angeles County Flood Control District	1	500	3.0	3,100	7.0
Concow Dam	Thermalito Irrigation District and Table Mountain Irrigation District	1	130	0.4	5,100	24.0
Conejo Pump Station (Pipeline)	Calleguas Municipal Water District	2	600	3.0	2,850	7.7
Conn Creek Dam	(See Lake Hennessey)					
Corona (Pipeline)	Metropolitan Water District of Southern California	2,5	2 800	18.0	1,700	3.3

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Cottonwood No. 1 (Canal)	California Department of Water Resources	2,7	17 000	115.0	2,837	5.0
Cottonwood No. 2 (Canal)	California Department of Water Resources	2	12 000	90.0	1,450	2.3
Covina (Pipeline)	Metropolitan Water District of Southern California	2,5	2 500	16.9	1,800	3.3
Coyote Creek (Dam)	Hidden Valley Lake Association	1	90	0.4	5,450	18.3
Coyote Creek (Pipeline)	Metropolitan Water District of Southern California	2,5	2 900	19.6	1,700	3.1
Coyote Dam	(See Lake Mendocino)					
Dahlia Drop (Canal)	Imperial Irrigation District	1	225	1.0	4,350	13.2
Deer Creek Colletion Pipeline	Cucamonga County Water District	1	200	1.0	4,500	12.2
Dodge Ave Check (Canal)	Orange Cove Irrigation District	2	475	2.4	3,200	8.6
Dominguez Gap Barrier (Pipeline)	Los Angeles County Flood Control District	1	500	2.0	3,100	10.5
Doris Dam	U. S. Fish and Wildlife Service	1	50	0.1	5,600	54.6
Early Intake Dam	City and County of San Francisco	1	1 300	8.7	2,050	4.0
East Highline Canal Turnout	Imperial Irrigation District	1	1 800	10.0	1,950	4.4
East Park Dam	U. S. Water and Power Resources Service	3	900	2.0	2,300	13.5
Eastside Pipeline	Lost Hills Water District	1	1 000	3.0	2,150	9.3
El Dorado Distribution System (Pipelines)						
Reservoir A	El Dorado Irrigation District	1	730	3.2	2,550	7.9
Reservoir 2	El Dorado Irrigation District	2	50	0.2	5,600	27.3
Reservoir 2A	El Dorado Irrigation District	1	480	2.1	3,200	9.9
Reservoir 2A-3	El Dorado Irrigation District	2	360	1.6	3,650	11.1
Reservoir 3	El Dorado Irrigation District	1	200	0.9	4,500	14.0
Reservoir 5	El Dorado Irrigation District	1	60	0.3	5,600	21.8
Reservoir 6	El Dorado Irrigation District	1	80	0.3	5,500	22.7
Reservoir 8	El Dorado Irrigation District	1	175	0.8	4,700	14.4
Reservoir 9A	El Dorado Irrigation District	1	175	0.8	4,700	14.4
Reservoir 9B	El Dorado Irrigation District	1	90	0.4	5,450	18.4
Reservoir 10A	El Dorado Irrigation District	1	175	0.8	4,700	14.4

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Reservoir 10B	El Dorado Irrigation District	1	60	0.3	5,600	21.8
El Segundo Distribution System (Pipeline)	City of El Segundo	2	500	3.9	3,100	5.4
Emerald Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal Water District	2	340	1.5	3,700	11.3
Etiwanda Pressure Reducing Station (Pipeline)	San Gabriel Valley Municipal Water District	2	250	1.1	4,200	12.9
Farmington Dam	U. S. Army Corps of Engineers	1	400	2.0	3,450	9.3
Fisher Drop (Canal)	Merced Irrigation District	1	75	0.3	5,500	24.1
Folsom Lake Pipeline	U. S. Water and Power Resources Service	2,4	500	2.4	3,100	8.7
Franklin Inlet (Pipeline)	City of Los Angeles	1	800	6.8	2,450	3.9
French Lake (Dam)	Nevada Irrigation District	1	200	0.8	4,500	15.8
Fresno Main Canal						
Headworks	Fresno Irrigation District	1	650	2.6	2,700	9.1
Boos Check	Fresno Irrigation District	1	650	2.6	2,700	9.1
Dresser Check	Fresno Irrigation District	1	650	2.6	2,700	9.1
Gibraltar Dam	City of Santa Barbara	3	1 500	4.0	2,000	9.8
Grant Lake (Dam)	City of Los Angeles	1	1 500	3.0	2,000	13.0
Guadalupe Dam	Santa Clara Valley Water District	1	60	0.3	5,600	21.8
Hell Hole Reservoir (Lower Hell Hole Dam)	Placer County Water District	2,5	550	3.0	2,975	7.4
Henshaw Dam	Vista Irrigation District	1	200	1.0	4,500	12.6
Hensley Lake (Hidden Dam)	U. S. Army Corps of Engineers	4	1 300	4.0	2,050	8.7
Hetch Hetchy Reservoir (O'Shaughnessy Dam)	City and County of San Francisco	2	1 600	6.0	2,000	6.9
Hickman Spillway	Turlock Irrigation District	1	2 100	4.5	1,850	10.8
Hidden Dam	(See Hensley Lake)					
Highland Avenue Pumping Plant (Pipeline)	City of Redlands	2	600	2.6	2,850	8.9
Hour House Dam	Yuba County Water Agency	1	100	0.3	5,450	27.3
Hume Lake (Dam)	U. S. Forest Service	4	1 050	4.6	2,150	6.4

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
H.V. Eastman Lake (Buchanan Dam)	U. S. Army Corps of Engineers	4	3 000	9.0	1,700	7.1
Ice House Reservoir (Dam)	Sacramento Municipal Utility District	2	10 000	22.0	--	--
Indian Creek Dam	South Tahoe Public Utility District	1	50	0.1	5,600	54.6
Irvine Lake Pipeline	Irvine Ranch Water District	2	500	1.0	3,100	20.9
Isabella Dam	U. S. Army Corps of Engineers	3	8 000	18.5	1,550	8.0
Jackson Creek Dam	(See Lake Amador)					
Jackson-Sutter Creek Outfall Pipeline	Amador County Water Agency	1	60	0.2	5,600	31.8
Jameson Lake (Juncal Dam)	Montecito County Water District	1	60	0.4	5,600	16.4
Juncal Dam	(See Jameson Lake)					
Kaiser Pipeline	Georgetown Divide Public Utility District	1	120	0.3	5,100	29.1
Kent Lake (Peters Dam)	Marin Municipal Water District	1	150	0.4	4,950	26.0
Kern Island Canal Control Structure	City of Bakersfield, et al	1	700	3.1	2,600	7.9
Lake Arrowhead Dam	Arrowhead Lake Association	1	75	0.3	5,500	24.1
Lake Clementine (North Fork Dam)	U. S. Army Corps of Engineers	3	12 000	63.5	1,400	3.2
Lake Curry (Pipeline)	City of Vallejo	1	50	0.3	5,600	27.3
Lake Davis-Portola Pipeline	Plumas County Flood Control and Water Conservation District	1	60	0.3	5,600	21.8
Lake Eleanor Dam	City of San Francisco	1	60	0.3	5,600	21.8
Lake Fordyce Dam	Pacific Gas and Electric Company	1	900	4.0	2,300	6.7
Lake Hemet Dam	Lake Hemet Municipal Water District	1	75	0.1	5,500	72.2
Lake Hennessey (Conn Creek Dam)	City of Napa	1	500	2.3	3,100	9.1
Lake Hodges Dam	City of San Diego	1	270	1.2	4,150	12.6
Lake Kaweah (Terminus Dam)	U. S. Army Corps of Engineers	3	4 000	20.0	1,650	4.0
Lake Loveland Dam	South Bay Irrigation District	1	100	0.5	5,450	16.4
Lake Mary and Twin Lakes Open Diversion (Pipeline)	Mammoth County Water District	1	300	0.8	3,900	19.7
Lake Mendocino (Coyote Dam)	U. S. Army Corps of Engineers	2,4	4 000	21.0	1,650	3.8
Lake Pillsbury (Scott Dam)	Pacific Gas and Electric Company	1	5 000	15.0	1,600	6.4
Lake Piru (Santa Felicia Dam)	United Water Conservation District	3	3 600	7.8	1,650	9.1

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Lake Siskiyou (Box Canyon Dam)	Siskiyou County Flood Control and Water Conservation District	2,4	6 000	21.9	1,600	5.3
Lake Thomas A. Edison (Vermillion Valley Dam)	Southern California Edison	1	2 000	9.6	1,900	4.9
Lake Valley Dam	Pacific Gas and Electric Company	1	75	0.3	5,500	24.1
Lake Yosemite Dam	Merced Irrigation District	1	1 200	2.3	2,050	13.9
Lateral A (Chute)	Tulare Lake Basin Water Storage District	1	1 600	7.0	2,000	5.9
Lateral B (Chute)	Tulare Lake Basin Water Storage District	1	900	4.0	2,300	6.7
Lexington Dam	Santa Clara Valley Water District	1	500	2.9	3,100	7.2
Little Grass Valley Dam	Oroville-Wyandotte Irrigation District	1	2 600	6.5	1,750	8.8
Littlerock Dam	Palmdale Water District	1	50	0.2	5,600	27.3
Lopez Dam	San Luis Obispo County Flood Control and Water Conservation District	1	50	0.4	5,600	13.7
Los Angeles Distribution System (Pipelines)						
Location 1	City of Los Angeles	1	610	3.3	2,850	7.1
Location 2	City of Los Angeles	1	270	2.2	4,150	6.9
Location 3	City of Los Angeles	1	420	2.1	3,400	9.1
Location 4	City of Los Angeles	1	270	1.8	4,150	8.4
Location 5	City of Los Angeles	1	140	1.2	4,950	8.1
Location 6	City of Los Angeles	1	190	1.1	4,500	10.9
Location 7	City of Los Angeles	1	120	1.0	5,100	8.9
Location 8	City of Los Angeles	1	130	0.8	5,100	12.0
Location 9	City of Los Angeles	1	70	0.6	5,500	11.6
Location 10	City of Los Angeles	1	100	0.6	5,450	13.6
Location 11	City of Los Angeles	1	70	0.6	5,500	11.6
Location 12	City of Los Angeles	1	100	0.6	5,450	13.6
Location 13	City of Los Angeles	1	60	0.5	5,600	13.1
Location 14	City of Los Angeles	1	60	0.5	5,600	13.1
Location 15	City of Los Angeles	1	1 000	8.2	2,150	3.4
Location 16	City of Los Angeles	1	1 800	9.0	1,950	4.9

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Los Angeles Reservoir (Dam)	City of Los Angeles	1	6 200	37.0	1,600	3.2
Los Banos Detention Dam	U. S. Water and Power Resources Service	1	100	0.5	5,450	16.4
Los Padres Dam	California American Water Company	1	75	0.3	5,500	24.1
Lost Creek Diversion Dam	U. S. Forest Service	3	1 800	10.0	1,950	4.4
Lower Hell Hole Dam	(See Hell Hole Reservoir)					
Lower Mokelumne River Project	(See Camanche Dam)					
Lyons Dam	Pacific Gas and Electric Company	2	300	1.5	3,900	10.5
Madera Canal						
Station 1064+67	U. S. Water and Power Resources Service	2	560	1.9	2,975	11.8
Station 1910+60	U. S. Water and Power Resources Service	2	650	2.6	2,700	9.1
Mallard Reservoir (Pipeline)	Contra Costa County Water District	1	200	0.9	4,500	14.0
Matilija Dam	Ventura County Flood Control District	1	700	2.0	2,600	12.3
Martis Creek Dam	U. S. Army Corps of Engineers	1	250	1.1	4,200	12.9
McCloud Dam	Pacific Gas and Electric Company	1	1 200	5.4	2,050	5.9
McCoy Flat Dam	Lassen Irrigation Company	1	50	0.2	5,600	27.3
Middle Fork Dam	(See Schadds Reservoir)					
Miramar Treatment Plant (Pipeline)	City of San Diego	2	1 300	5.7	2,050	6.1
Moccasin Lower Dam	City of San Francisco	2	1 600	7.0	2,000	5.9
Mojave Siphon No. 2 (Silverwood Lake Inlet Pipeline)	California Department of Water Resources	2	10 000	78.0	1,500	2.3
Mono Creek Diversion Dam	Southern California Edison	1	8/	8/	--	--
New Hogan Dam	U. S. Army Corps of Engineers	2,4	2 250	9.5	1,850	5.7
Newside Drop (Canal)	Imperial Irrigation District	1	200	0.9	4,500	14.0
New Siphon Drop (Yuma Main Canal)	U. S. Water and Power Resources Service	2,3	1 410	11.3	2,000	3.2
Nicasio Dam	Marin Municipal Water District	1	400	1.7	3,450	11.0
North Fork Dam	(See Lake Clementine and Pacheco Lake)					
Orange County (OC) 28 (Pipeline)	Orange County Water District	1	6 300	12.0	1,600	10.2
Orange County (OC) 45 (Pipeline)	City of La Habra	1	100	0.4	5,450	20.4

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Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Orange County (OC) 59 (Pipeline)	Orange County Water District	1	5 000	9.4	1,600	10.2
O'Shaughnessy Dam	(See Hetch Hetchy Reservoir)					
Pacheco Lake (North Fork Dam)	Pacheco Pass Water District	1	60	0.3	5,600	21.8
Pacoima Dam	Los Angeles County Flood Control District	1	400	1.0	3,450	18.6
Palo Verde Diversion Dam	U. S. Water and Power Resources Service	2,3	8 700	65.0	1,500	2.6
Parker Drop (Canal)	South San Joaquin Irrigation District	1	300	0.8	3,900	19.7
People's Weir (Canal)	People's Ditch Company	1	2 200	3.5	1,850	14.5
Perris Power Project (Pipeline)	Metropolitan Water District of Southern California	2,5	7 900	40.3	1,550	3.6
Peters Dam	(See Kent Lake)					
Pilarcitos Dam	City of San Francisco	1	200	0.8	4,500	15.8
Point Loma Wastewater Treatment Plant (Pipeline)	City of San Diego	1	1 200	8.0	2,050	4.0
Ponderosa Diversion Dam	Oroville-Wyandotte Irrigation District	1	3 300	14.0	1,700	5.0
Prosser Creek Dam	U. S. Water and Power Resources Service	2,4	1 000	3.5	2,150	8.0
Rector Creek Dam	California Department of Finance	1	100	0.5	5,450	16.4
Red Bluff Diversion Dam	U. S. Water and Power Resources Service	2,4	14 000	70.0	1,400	3.4
Redlands Water Treatment Plant (Pipeline)	City of Redlands	2	200	0.9	4,500	14.0
Reservoir A (Pipeline)	El Dorado Irrigation District	1	730	3.2	2,550	7.9
Rindge Dam	Adamson Companies	1	600	0.9	2,850	25.7
Rio Hondo (Pipeline)	Metropolitan Water District of Southern California	2,5	2 000	12.3	1,900	4.0
Robert A. Skinner Dam	Metropolitan Water District of Southern California	1	1 400	6.3	2,000	5.8
Robert W. Matthews Dam	(See Ruth Reservoir)					
Round Valley Dam	Jack and Thomas Swickward	2	90	0.4	5,450	18.4
Ruth Reservoir (Robert W. Matthews Dam)	Humboldt Bay Municipal Water District	2,4	4 000	14.2	1,650	5.6
Salt Spring Valley Reservoir (Dam)	Rock Creek Water District	1	90	0.4	5,450	18.4
Saeltzar Dam	Flat Water Ditch Company	4	875	6.5	2,350	4.1

See footnotes on first page

Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Sand Bar Project (Dam)	Oakdale and South San Joaquin Irrigation Districts	4	12 000	70.0	1,400	2.9
Sand Creek Check (Canal)	Orange Cove Irrigation District	1	200	1.5	4,500	8.4
San Dieguito Treatment Plant (Pipeline)	San Dieguito Water District and Santa Fe Irrigation District	2	1 000	4.5	2,150	6.2
San Dimas Dam	Los Angeles County Flood Control District	1	100	0.3	5,450	27.3
San Dimas (Pipeline)	Metropolitan Water District of Southern California	2,7	9 900	68.2	1,500	2.6
San Gabriel Dam	Los Angeles County Flood Control District	2	500	3.0	3,100	7.0
Santa Anita Dam	Los Angeles County Flood Control District	1	300	0.7	3,900	22.6
Santa Felicia Dam	(See Lake Piru)					
Santiago Creek (Pipeline)	Metropolitan Water District of Southern California	2,3	3 000	15.6	1,700	4.1
San Vicente Reservoir (Pipeline)	San Diego County Water Authority	2	850	3.4	2,375	7.7
Schaads Reservoir (Middle Fork Dam)	Calaveras Public Utility District	1	75	0.4	5,500	16.0
Scotts Flat Dam	Nevada Irrigation District	1	1 300	5.5	2,050	6.3
Scott Dam	(See Lake Pillsbury)					
Semitropic Intake Canal	Semitropic Water Storage District	1	8/	8/		
Sepulveda Canyon (Pipeline)	Metropolitan Water District of Southern California	2,7	8 600	56.2	1,500	2.8
Sidney N. Peterson Water Treatment Plant (Pipeline)	San Juan Suburban Water District	2	175	0.4	4,700	28.8
Slab Creek Dam	Sacramento Municipal Utility District	6	400	3.0	3,450	6.2
Snow Creek (Pipeline)	Desert Water Agency	1	300	1.7	3,900	9.3
South Canal	Pacific Gas and Electric Company	2	8 000	37.0	1,550	4.0
South Portal Doulton Tunnel	Montecito County Water District	1	200	0.5	4,500	25.2
Spicers Meadows Dam	Pacific Gas and Electric Company	1	750	3.3	2,550	7.8
Stevens Creek Dam	Santa Clara Valley Water District	1	75	0.3	5,500	24.1
Stone Canyon Dam	City of Los Angeles	2	300	2.0	3,900	7.9
Stony Gorge Dam	U. S. Water and Power Resources Service	4	6 000	18.0	1,600	6.4

See footnotes on first page

Table 11. Project Cost and Energy Cost in 1984 for 285 Potential Hydroelectric Facilities (Continued)

Facility	Owner	Status of Development	Capacity (kW)	Energy (GWh/yr)	1984 Project Cost ($/kW)	1984 Energy Cost (¢/kWh)
Success Dam	U. S. Army Corps of Engineers	4	4 000	12.0	1,650	6.6
Sweetwater Treatment Plant (Pipeline)	San Dieguito Water District and Santa Fe Irrigation District	2	1 400	6.3	2,000	5.8
Temescal (Pipeline)	Metropolitan Water District of Southern California	2,5	2 800	18.0	1,700	3.3
Terminal Reservoir Inlet (Pipeline)	San Luis Obispo County Flood Control and Water Conservation District	2	75	0.6	5,500	10.7
Terminus Dam	(See Lake Kaweah)					
Tinemaha Dam	City of Los Angeles	2	1 600	8.3	2,000	5.0
Tuberose Check (Canal)	Imperial Irrigation District	1	200	1.3	4,500	10.0
Tule Lake (Dam)	R. W. Akers	1	75	0.3	5,500	24.1
Upper Dawson Powerplant (Canal)	Turlock Irrigation District	5	4 000	15.9	1,650	5.0
Upper Main Canal	Browns Valley Irrigation District	1	200	0.9	4,500	14.0
Vail Dam	Rancho California Water District	1	200	0.9	4,500	14.0
Valley View (Pipeline)	Metropolitan Water District of Southern California	2,5	2 400	14.2	1,800	3.8
Van Owen Regulating (Pipeline)	City of Los Angeles	1	600	5.0	2,850	4.6
Venice (Pipeline)	Metropolitan Water District of Southern California	2,7	10 100	60.0	1,500	3.0
Vermillion Valley Dam	(See Lake Thomas A. Edison)					
Volta No. 2 Powerhouse (Canal)	Pacific Gas and Electric Company	7	1 000	5.0	2,150	6.0
Warm Springs Dam	U. S. Army Corps of Engineers	2,3	3 000	15.0	1,700	4.3
Webber Dam	El Dorado Irrigation District	1	75	0.3	5,500	24.1
West Valley Dam	South Fork Pit River Irrigation District	1	900	3.8	2,300	7.1
White Pines Dam	Calaveras County Water District	1	100	0.4	5,450	20.4
Whitewater Canyon Irrigation System (Pipeline)	Whitewater Canyon Mutual Water Company	2	400	2.5	3,450	7.5
Whitewater River (Pipeline)	Desert Water Agency	1	400	2.4	3,450	7.8
Yorba Linda Feeder (Pipeline)	Metropolitan Water District of Southern California	2,7	5,100	33.5	1,600	2.9
Youd Drop (Canal)	Merced Irrigation District	1	100	0.5	5,450	16.4
Yuma Main Canal	(See New Siphon Drop)					

See footnotes on first page

Table 12. Summary of Facilities Cost Effective in 1984, by 1989, and Those Not Likely to be Cost Effective

	Cost Effective								
	In 1984			By 1989			Not Likely		
Group	Facilities (No.)	Capacity (kW)	Energy (GWh/yr)	Facilities (No.)	Capacity (kW)	Energy (GWh/yr)	Facilities (No.)	Capacity (kW)	Energy (GWh/yr)
(1)	16	21 875	91	5	1 325	4	7	2 040	7
(2)	36	134 135	610	5	14 720	47	1	450	1
(3)	115	311 990	1 549	63	19 955	69	37	3 510	2
TOTAL	167	468 000	2 250	73	36 000	120	45	6 000	10

(1) Sites studied by the Department (28).
(2) Sites studied by others (42).
(3) Information obtained from questionnaires (215 sites).

CHAPTER IV

PROCEDURES FOR SITE DEVELOPMENT

The procedures for obtaining the permit approvals and environmental reviews required for retrofitting small hydroelectric facilities are considerably less complex than those for most other energy development projects of similar size. However, this does not mean that they are simple or that they can be completed quickly. In this chapter, the procedures are explained in the context of overall facility planning, obtaining approvals, design, and construction. As with facility design and construction, most prospective small hydroelectric developers should engage a qualified consultant to do project planning work and obtain approvals.

The steps that must be taken to develop a small hydroelectric project are listed, in sequence, in Table 13.

Because some steps can be carried out concurrently, usually only about 36 months will elapse between the reconnaissance survey and the full operation of the project. If the site owner chooses to apply for a PURPA

Table 13. Steps Required to Develop a Small Hydroelectric Project

Step	Estimated Completion Time	Reference in this Report
(1) Reconnaissance Survey	1-3 days	Chapter IV
(2) FERC Preliminary Permit Application and Processing	4-9 months	Appendix C
(3) Preliminary Feasibility Study	1-3 months	Chapter III
(4) DOE Feasibility Loan Application and Processing	1.5-3 months	Appendix C
(5) Final Feasibility Study	4 months	Chapter IV
(6) DOE License Loan Application and Processing	3 months	Appendix D
(7) Licensing, Permit Approvals, and Environmental Review	12 months	Appendix C
(8) Financing: Short-term and Long-term	4 months	Appendix D
(9) Preparation of Plans and Specifications	6 months	Appendix C
(10) Manufacture of Equipment	10-12 months	Appendix E
(11) Construction and Testing	9-12 months	-

Lake Fordyce, on Fordyce Creek in Nevada County, is owned by the Pacific Gas and Electric Company. A 900-kilowatt hydroelectric power plant at this site could generate 4 million kilowatthours of electricity annually. This amount of energy is equivalent to burning 6,800 barrels of oil in a fossil-fuel power plant. (Photo by DWR Division of Safety of Dams)

Title IV loan either to finance the final feasibility study or to apply for the FERC license or both, about 3 to 6 months must be added to the schedule. Before granting such a loan, however, the U. S. Department of Energy (DOE) requires that developers obtain either a preliminary permit or a license exemption.

The steps for developing a small hydroelectric project are discussed below. A generalized schedule for the development of a small hydroelectric facility is presented in Figure 13.

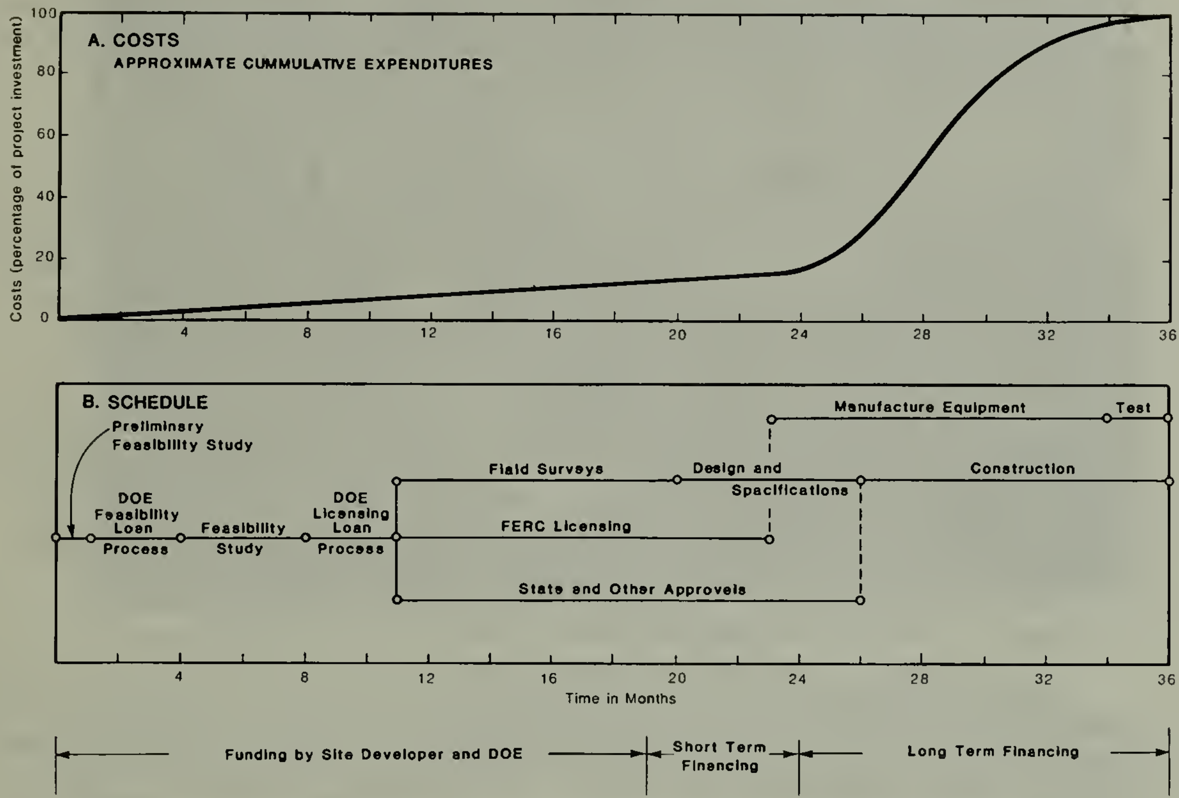
Reconnaissance Survey

The reconnaissance survey is used to determine whether a hydroelectric potential exists at a given site. Specifically, the investigator must determine how much water falls through what distance. If a field investigation and preliminary computation show that the site has little or no potential, further development can stop before the owner or developer has made any significant investment.

Preliminary Permit Application

If the reconnaissance results are favorable, the developer next applies to FERC for a preliminary permit or an exemption. [A sample application and the instructions for completing it are included in Appendix F.] The preliminary permit gives a permittee priority in applying for a FERC license to develop the site. A FERC license exemption provides exclusive development rights to the site owner. The preliminary permit or license exemption is a prerequisite to obtaining a DOE loan for the final feasibility study.

Figure 13 Typical Costs and Schedule for Developing a Small Hydroelectric Project



SOURCE: USCE

Dahlia Drop, on the Central Main Canal in Imperial County, is owned by the Imperial Irrigation District. A 225-kilowatt hydroelectric power plant at this site could generate 1 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 1,700 barrels of oil annually in a fossil-fuel plant. (Photo by DWR Energy Division)

Preliminary Feasibility Study

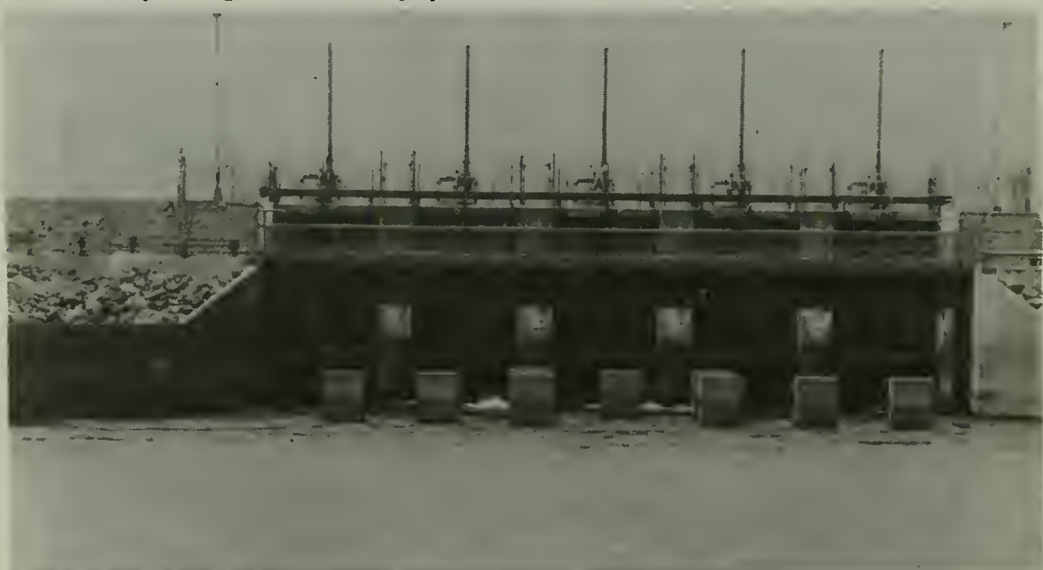
In the preliminary feasibility study, the full potential of the site is realistically assessed at a minimum cost. The results of the study will help the developer to decide whether to spend more money, apply for a Title IV loan to finance the final feasibility study, or both.

The preliminary feasibility study presents the greatest financial risk. Therefore, a developer (without in-house capability) should have a qualified engineer determine whether the site lacks potential due to technical, economical, or environmental reasons; whether it would be economically marginal during its early years of operation; or whether it shows a definite promise of being both technically and economically feasible. Examples of preliminary feasibility studies are presented in Appendix C.

The cost of a preliminary feasibility study should be about \$3,000 to \$5,000, depending on the complexity of the site and the availability of reference material such as drawings of existing structures, streamflow data, etc. The study should provide enough information to support an application for a Title IV loan to finance the final feasibility study.

Feasibility Loan Application and Processing

A loan program established by DOE can provide up to 90 percent of the cost of the final feasibility study at a rate of 7.25 percent interest. A developer can obtain up to \$50,000 for a ten-year term; repayment is not required during the first four years. Moreover, if the final feasibility study reveal that the proposed project is not technically or economically sound, DOE may forgive the repayment of the loan.



Thermalito Afterbay River Outlet, adjacent to the Feather River in Butte County, is owned by the California Department of Water Resources. A 13 000-kilowatt hydroelectric power plant at this site could generate 43 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 73,000 barrels of oil annually in a fossil-fuel power plant.
(Photo by DWR Energy Division)

Thermalito Diversion Dam, on the Feather River in Butte County, is owned by the California Department of Water Resources. A 3 000-kilowatt hydroelectric power plant at this site could generate 24 million kilowatthours of electricity annually. This amount of energy is equivalent to burning 41,000 barrels of oil in a fossil-fuel power plant. (Photo by DWR Energy Division)

Final Feasibility Study

If the results of the preliminary feasibility study are favorable, the next step is to refine the preliminary estimates of the project's capacity, energy output, and construction costs. In some cases, if feasibility is definitely indicated and sufficient records of streamflow are available, this refinement process can await final design. In other cases, the results of the preliminary feasibility study can be used to prepare the FERC license application. Usually, however, the estimates of capacity, streamflow, and costs will have to be refined during a final feasibility study in order to determine the optimal size of the turbine/generator.

The feasibility study must

1) determine the installed capacity, the number of generating units required (usually one unit for a small hydroelectric facility), and the size and type of supporting physical works;

2) prepare detailed estimates of construction costs;

3) develop ownership and operating criteria for the facility;

4) estimate energy generation under wet-year, normal, and dry-year streamflow conditions; and

5) identify the constraints on development of the site. Financial, legal, environmental, and socioeconomic constraints may affect a project adversely or even prevent its development.

The major factors that influence the layout of the project are the head and flow, the performance characteristics of the turbine/generator, the size of the structure needed to house the equipment, and the configuration of the facilities.

Licensing Loan Application and Processing

If the results of the final feasibility study are favorable, the next step is to apply for a DOE licensing loan. As under the DOE Feasibility Loan Program, a developer may obtain up to $50,000 for a ten-year term at 7.25 percent interest. Part of the loan may be used to defer the cost of obtaining the necessary environmental and other approvals by state, federal, and local agencies.

License and Permit Approvals, and Environmental Review

The final feasibility study will provide enough technical information for the license and permit applications. The licensing and approval processes (discussed in detail in Appendix F) are quite involved and require about a year to complete. Since similar information is required for the various state and federal applications, totally new information need not be generated for each application. It may be necessary to obtain licenses, permits, certificates, and approvals from several state, federal, and local agencies (Table 14). The authority, responsibility, and requirements of these federal, state, and local agencies are discussed in Appendix F.

Table 14. Agencies Whose Approvals for Small Hydroelectric Projects Are Required

Federal	State	Local
Federal Energy Regulatory Commission (FERC)	Department of Fish and Game	Counties
	Department of Water Resources	Special Districts
U. S. Army Corps of Engineers	State Lands Commission	Municipalities
U. S. Bureau of Land Management	State Water Resources Control Board	
U. S. Forest Service	Office of State Treasurer (District Securities Division)	
U. S. Water and Power Resources Service		

Financing

Short-Term Financing. As soon as the FERC license is approved and it is known that other approvals are imminent, the developer should begin to develop the final design, and prepare specifications and bid documents. By this time, the loan funds for the feasibility study and licensing will be running out, and long-term financing for construction, such as bonds and other government loans, will probably not be arranged yet.

To finance the project at this stage, a developer can use a variety of financial resources, including private financing, certain government loans, or a combination of the two (see Appendix H). For this phase of the project, a developer should consult an experienced financial adviser concerning short-term, and long-term financing.

Long-Term Financing. Long-term financing arrangements should be completed by the time the order for turbine/generator is placed. The manufacture of the hydroelectric generating equipment requires from 10 to 12 months. The manufacturer will require a down payment and subsequent progress payments while the equipment is being fabricated.

Sources of long-term loans include bonds, private financing, and government loans. Tax-exempt bonds, such as general- obligation or certain revenue bonds, can usually be issued by public agencies, and taxable revenue bonds can be issued by either public or private agencies. Private financing includes equity and mortgage loans. Income tax credits provided by the Windfall Profits Tax Act of 1979 encourage private financing. Several government agencies issue construction loans at low-interest, usually around five percent; they include the U.S. Department of Housing and Urban Development and the U.S. Department of Agriculture.

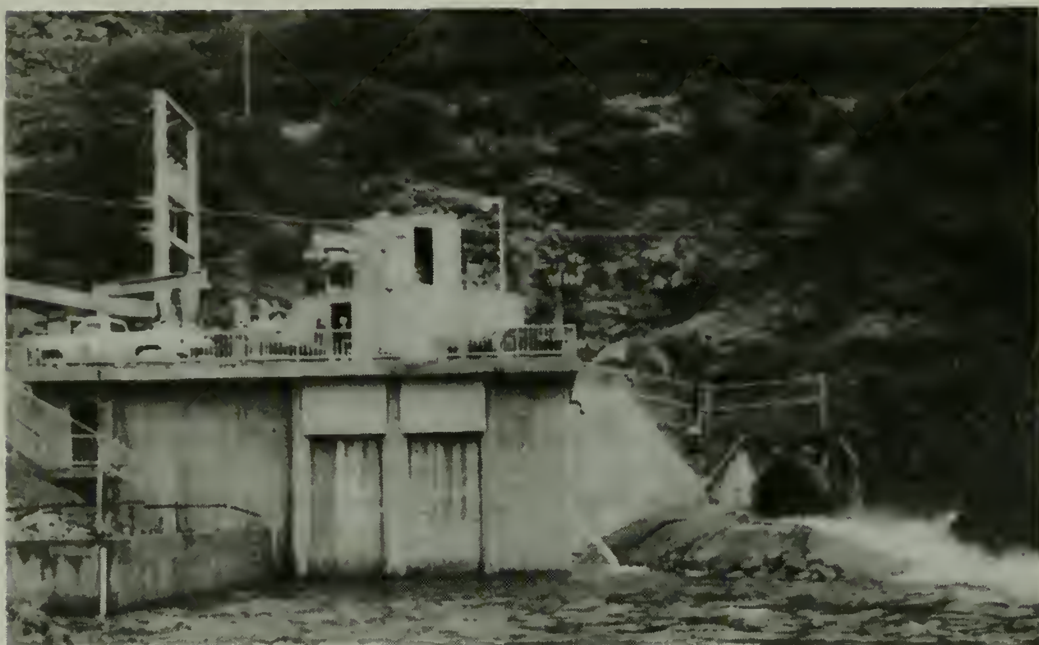
The California Legislature has established several programs to assist renewable resource technologies and to provide financing assistance for the development of small hydroelectric projects. Appendix H contains descriptions of these programs and the name and address of the agencies responsible for their administration.

Design and Construction

Preparation of Plans and Specifications. The preparation of contract plans and specifications requires about 6 months.

Manufacture of Equipment. Since it takes about one year to manufacture the turbine and generator, the contract for those items should be awarded as soon as possible. Their manufacture should proceed concurrently with design and construction of the civil works. Usually, a separate contract for the turbine/generator is awarded before the design of the civil works has been completed. Delivery of the turbine/generator should be coordinated with construction of the plant structure.

Construction and Testing. Construction usually takes about 9 to 12 months, depending on the complexity of the project. Following this, a month or two of operational testing will be required. This should be conducted by an engineer and should include the training of operation and maintenance personnel.



Rollins Dam, on the Bear River in Nevada County, is owned by the Nevada Irrigation District. Here, a 12 000-kilowatt hydroelectric power plant generates 60 million kilowatthours of electricity per year. This amount of energy is equivalent to burning 102,400 barrels of oil in a fossil-fuel power plant.
(Tudor Engineering Company Photo)

GLOSSARY

ACRE-FOOT (ac-ft, AF) -- The amount of water required to cover one acre to a depth of one foot. This is equivalent to 325,851 gallons, 43,560 cubic feet, 1,233.5 cubic metres, or 1.2335 cubic dekametres.

ADVERSE WATER CONDITIONS -- Water conditions that limit the hydroelectric generation by either a low water supply or a reduced HEAD.*

ALTERNATING CURRENT (ac, AC) -- Electricity that reverses its direction of flow periodically, as contrasted to DIRECT CURRENT.

AMORTIZATION -- The paying of a debt with installment payments or with a SINKING FUND. Also writing off expenditures by prorating them over a period.

APPRAISAL STUDY -- A preliminary feasibility study made to determine if a detailed FEASIBILITY STUDY is warranted. Also called a reconnaissance study.

AVAILABILITY FACTOR -- The percentage of time a plant is available for power production.

AVERAGE-WATER YEAR -- The average annual flow of water available for hydropower generation calculated over a long period, usually 10 to 50 years.

AVOIDED COST -- The payment made for the capacity and energy of a small power project; such payment equals the cost to a utility of obtaining and operating additional generating units, or to purchase power from another source, if this power were not available. Also called avoidable cost.

BARREL (bbl) -- The measure used for crude oil; it is equal to 42 U.S. gallons (gal).

BARREL-OF-OIL EQUIVALENT -- (BOE). A unit of energy equal to the energy contained in a BARREL of crude oil or 5,800,000 Btu.

BASE LOAD -- The amount of electric power needed to be delivered at all times and all seasons.

BASE LOAD STATION -- A power generating station usually operated at a constant output to take all or part of the BASE LOAD of a system.

BENEFIT-COST RATIO (B/C) -- The ratio of the present value of the benefit (e.g. revenues from power sales) to the present worth of the project cost.

BOE -- See BARREL-OF-OIL EQUIVALENT.

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*Capitalized terms indicate those defined elsewhere in this glossary.

BRITISH THERMAL UNIT (Btu) -- The quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

BTU -- See BRITISH THERMAL UNIT (Btu).

BLM -- Bureau of Land Management.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA) -- An act, passed in 1970, that requires that the environmental impact of most projects and programs be identified. Among its important provisions is one requiring that a detailed statement of the environmental impact of, and alternatives to, a project be submitted to the California State or local government before the project can begin.

CAPACITY -- The maximum power output or the load for which a generating unit, generating station, or other electrical apparatus is rated. Common units include kilovolt-ampere (kVA), KILOWATT (kW), and MEGAWATT (MW).

CAPACITY FACTOR -- The ratio of the energy that a plant produces to the energy that would be produced if it were operated at full capacity throughout a given period, usually a year. Sometimes called the plant factor.

CAPACITY VALUE -- The part of the market value of electric power that is assigned to DEPENDABLE CAPACITY.

CAPITAL EXPENDITURES -- The construction cost of a new facilities (additions, betterments, and replacements) and expenditures for the purchase or acquisition of existing utility plant facilities. Also called capital outlay.

CAPITAL OUTLAY -- See CAPITAL EXPENDITURES.

CAPITALIZED COST -- A method used to compare the costs of alternatives; it is equal to the sum of the initial costs and the present worth of annual payments, such as operation and maintenance costs.

CAPITAL RECOVERY -- See DEBT SERVICE.

CAPITAL RECOVERY FACTOR -- A factor used to convert an investment into an equivalent annual cost at a given interest rate for a specified period.

CDWR -- California Department of Water Resources; also DWR.

CEC -- California Energy Commission. (Officially, the Energy Resources Conservation and Development Commission.)

CEQA -- CALIFORNIA ENVIRONMENTAL QUALITY ACT.

CFS -- CUBIC FEET PER SECOND.

CHECK STRUCTURE -- A structure where water flow is regulated and measured.

CIRCUIT BREAKER -- A switch that automatically opens to cut off an electric current when an abnormal condition occurs.

CIVIL WORKS -- All the works of a facility associated with plant structures, impounding channeling, and emergency release of water, etc.

COGENERATION -- The use waste heat from an industrial plant to drive turbine-generators for electricity generation. Also, the use of low-pressure exhaust steam from an electric generating plant to heat an industrial process or a space.

CPUC -- California Public Utilities Commission, also PUC.

CUBIC FEET PER SECOND (cfs, ft^3/s) -- A flow equal to 646,317 gallons per day or 0.028317 cubic metres per second (m^3/s). Also called a SECOND FEET.

CRITICAL HEAD -- The HEAD at which the output of a turbine at full gate equals the NAMEPLATE RATING of an associated GENERATOR.

DEMAND -- The rate at which electrical energy is delivered to a system, to part of a system, or to a piece of equipment; it is usually expressed in KILOWATTS, MEGAWATTS, etc.

DESIGN HEAD -- The HEAD at which the RUNNER of a turbine is designed to provide the highest efficiency.

DEBT SERVICE -- The principal and interest payments made on a debt used to finance a project. Also called capital recovery.

DEPENDABLE CAPACITY -- The minimum capacity available at any time during a study period. This value is generally determined by optimizing plant operation during the driest period when the least water is available.

DIRECT CURRENT (dc, DC) -- Electricity that flows continuously in one direction, as contrasted with ALTERNATING CURRENT.

DOE -- U. S. Department of Energy.

DRAFT TUBE -- A large tube that takes the water discharged from a TURBINE at a high velocity and reduces its velocity by enlarging the cross-section of the tube.

DUMP ENERGY -- Energy generated by water that cannot be stored or conserved and when such energy is beyond the need of the producing utility.

DWR -- California Department of Water Resources, also CDWR.

EFFICIENCY -- The ratio of the output to the input of energy or power, usually expressed as percentage.

EIR -- An Environmental Impact Report prepared to satisfy the requirements of the CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA).

EIS -- An Environmental Impact Statement prepared to satisfy the requirements of the Federal NATIONAL ENVIRONMENTAL POLICY ACT (NEPA).

ELECTRICAL ENERGY UNITS -- Common units used to measure electrical energy include KILOWATTHOURS (kWh) and GIGAWATTHOUR (GWh, million kWh). A 100-watt light bulb lit for ten hours will consume one KILOWATTHOUR (kWh) of electrical energy. A one-MEGAWATT generating unit will produce 1000 kWh if it runs for one hour at full CAPACITY.

END USER -- Any ultimate consumer of electricity or of any type of fossil fuel (petroleum, coal, natural gas).

ENERGY -- The capability of doing work which occurs in several forms such as potential, KINETIC, thermal, and nuclear energy. One form of energy may be changed to another; the kinetic energy of falling water can be used to drive a turbine where the energy is converted into mechanical energy which can drive a generator to produce ELECTRICAL ENERGY.

ENERGY DISSIPATER -- A device used to reduce water pressure to a level safe for certain uses.

EXTRA HIGH VOLTAGE (EHV) -- A term applied to voltage levels of transmission lines which are higher than the voltage levels commonly used. At present, electric utilities consider EHV to be any voltage of 345,000 volts or higher. See ULTRAHIGH VOLTAGES.

FEASIBILITY STUDY -- An investigation to develop a project and definitively assess its desirability for implementation.

FEDERAL ENERGY REGULATORY COMMISSION (FERC) -- An agency in the U. S. Department of Energy, which licenses non-Federal hydropower projects and regulates the interstate transfer of electrical energy.

FERC -- FEDERAL ENERGY REGULATORY COMMISSION.

FIRM CAPACITY -- The load-carrying ability of a plant that would probably be available to supply energy for meeting LOAD at any time.

FIXED COSTS -- Costs associated with plant investment, including DEBT SERVICE, interim replacement, and insurance.

FLOW-DURATION CURVE -- A curve of flow values plotted in descending order of magnitude against time intervals, usually in percentages of a specified period. For example, the curve might show that over a period of a year, a river flows 500 CFS or more 10 percent of the time, and 100 CFS or more 80 percent of the time.

GENERATOR -- A machine that converts mechanical energy into ELECTRTICAL ENERGY.

GIGAWATTHOUR (GWh) -- One million KILOWATTHOURS (kWh).

GROUND WATER -- The supply of water under the earth's surface, as contrasted to SURFACE WATER.

HEAD -- The difference in elevation between two water surfaces. In hydropower, the net head refers to the difference in elevation between the headwater surface above and the tailwater surface below a HYDROPOWER PLANT, minus friction losses.

HORSEPOWER (hp) -- The equivalent of 0.746 KILOWATT (kW).

HYDROPOWER PLANT -- An electric power plant in which the energy of falling water is converted into electricity by turning a turbine-generator unit. Also called a hydroelectric power plant, a hydroelectric plant, or simply a hydro plant.

IMPOUNDMENT -- A reservoir or artificial pond created behind a dam.

INCREMENTAL COST -- The additional cost incurred when generating an added amount of power.

INSTALLED CAPACITY -- The total of the CAPACITIES shown on the nameplates of the generating units in a HYDROPOWER PLANT.

INTERRUPTIBLE ENERGY -- Energy that can be curtailed at the supplier's discretion.

KILO (k) -- A prefix meaning one thousand.

KILOWATT (kW) -- One thousand watts (W) or 1.34 HORSEPOWER (hp).

KILOWATTHOUR (kWh) -- One thousand watthours (Wh) - the amount of ELECTRICAL ENERGY produced or consumed by a one-KILOWATT unit for one hour.

KINETIC ENERGY -- The energy of motion; the ability of an object to do work because of its motion.

LOAD -- The amount of power required at a given point or points in an electric system.

LOAD FACTOR -- The ratio of the average load to the maximum load during a given period.

LOW-HEAD HYDROPOWER -- Hydropower that operates with a head of 20 metres (66 feet) or less.

MARKET VALUE -- The value of power at the load center, as measured by the cost of procuring equivalent alternative power to the market.

MEGA (M) -- A prefix meaning one million.

MEGAWATT (MW) -- One thousand KILOWATTS (kW) or one million watts (W).

MILL -- One tenth of a cent or one thousandth of a dollar.

MGD -- Million gallons per day, equivalent to 1.547 CUBIC FEET PER SECOND (cfs).

MWD -- The Metropolitan Water District of Southern California.

NAMEPLATE RATING -- The full-load continuous rating of a GENERATOR or other electrical equipment under specified conditions as designated by the manufacturer, and written on the nameplate.

NATIONAL ENVIRONMENTAL POLICY ACT (NEPA) -- An act, passed in 1969, requiring that the environmental impact of most projects and programs be identified. Among its important provisions is one requiring a detailed statement of environmental impact of, and alternatives to, a project to be submitted to the federal government before the project can begin.

NON-FOSSIL ENERGY -- Energy from sources other than fossil; non-fossil energy sources include nuclear, wind, tide, biomass, geothermal, water, and solar sources.

NEGATIVE DECLARATION -- The document which satisfies the CEQA requirement if no significant environmenal impacts would result from a project as determined by an initial study.

OFF-PEAK -- The time of day and week when the demand for electricity is low; see ON-PEAK.

ON-PEAK -- The time of day and week when demand for electricity in a region is high.

OUTAGE -- The period in which a facility is out of service.

OUTAGE, FORCED -- The shutdown of a facility for emergency reasons.

OUTAGE, SCHEDULED -- The shutdown of a facility for inspection or maintenance, as scheduled.

OUTPUT -- The amount of power or energy delivered from a piece of equipment, a station, or a system.

PEAKING UNIT -- An auxiliary electric power system that is used to supplement the power supply system during periods of peak demand for electricity. Peaking units are usually old, low cost, inefficient units having a high fuel cost, or hydroelectric units having low FIRM CAPACITY.

PENSTOCK -- A pressure pipe used to carry water to a TURBINE.

PGandE -- Pacific Gas and Electric Company.

PLANT FACTOR -- See CAPACITY FACTOR.

PRELIMINARY PERMIT -- An initial permit issued by the FEDERAL ENERGY REGULATORY COMMISSION (FERC) for hydropower projects. The permit does not authorize construction, but during the permit's term of up to 36 months, the permittee is given the right of priority-of-application for a license while completing the necessary studies to determine the engineering and economic feasibility of the proposed project, the market for the power, and all other information necessary for inclusion in an application for license.

PSI -- A unit of pressure as measured in pounds per square inch.

PUC -- See CPUC.

PUMPED-STORAGE PLANT -- A HYDROPOWER PLANT which generates electricity during periods of high demand by using water previously pumped into a storage reservoir during periods of low demand. Pumped storage returns only about two-thirds of the electricity put into it, but it can be more economical than obtaining and operating additional generating PEAKING UNITS.

PURPA -- Public Utility Regulatory Policies Act of 1978. This act requires utilities to purchase power from and interconnect with a privately developed facility and mandates the state utility regulatory agency to set a "just and reasonable price."

QUADRILLION -- Equivalent to 1×10^{15}.

QUADRILLION BTU (Quad) -- An amount of energy equal to the heat value of 965 billion cubic feet of gas, 175 million barrels of oil (BOE), or 38 million tons of coal.

RECONNAISSANCE STUDY -- See APPRAISAL STUDY.

REHABILITATION -- The restoration of an abandoned power plant to produce energy.

RETROFITTING -- Furnishing a plant with new parts or equipment not purchased or available at the time of manufacture or construction. In hydropower development, the term may refer to the installation of electric generating components at existing water facilities to produce electricity.

RIPARIAN RIGHTS -- The rights of a land owner to the water on or bordering his property, including the right to prevent diversion or misuse of upstream water.

ROYALTY -- The portion of the proceeds paid to the title holder in exchange for exploitation of a property.

RPM -- Revolution per minute.

RUNOFF -- The portion of rainfall, melted snow or irrigation water that flows over the surface and ultimately reaches streams.

RUNNER -- The part of a TURBINE, consisting of blades on a wheel or hub, which is turned by the pressure of high-velocity water.

RUN-OF-THE-RIVER PLANT -- A hydropower plant that uses the flow of a stream as it occurs with little or no reservoir capacity for storing water. Sometimes called a "STREAM FLOW" plant.

SBA -- Small Business Administration.

SCE -- Southern California Edison Company.

SDG&E -- San Diego Gas & Electric Company.

SECOND-FEET -- CUBIC FEET PER SECOND (cfs).

SEEPAGE -- Water that flows through the soil.

SERVICE AREA -- An area to which a utility system supplies electric service.

SINKING FUND -- A fund set up to accumulate a certain amount in the future by collecting a uniform series of payments.

SPILLWAY -- A passage used for running surplus water over or around a dam.

SPINNING RESERVE -- Generating capacity that is on the line in excess of the load on the system ready to carry additional electrical LOAD.

STANDBY SERVICE -- Service that is not normally used, but is available, in lieu of or as a supplement to, the usual source of supply.

STREAM FLOW -- The amount of water passing a given point in a stream or river in a given period, usually expressed in CUBIC FEET PER SECOND (cfs), or MILLION GALLONS PER DAY (mgd, MGD).

SUBSTATION -- An assemblage of equipment used to switch and/or change or regulate the voltage of electricity.

SURFACE WATER -- Water on the earth's surface that is exposed to the atmosphere such as rivers, lakes, oceans, as contrasted to GROUND WATER.

SURPLUS ENERGY -- Generated energy that is beyond the immediate needs of the producing system. This energy is usually sold on an interruptible basis.

SWITCHING STATION -- An assemblage of equipment used for the sole purpose of tying together two or more electric circuits through selectively arranged switched that permit a circuit to be disconnected in case of trouble or to change electric connections between circuits. A type of SUBSTATION.

TAILRACE -- The channel, downstream of the DRAFT TUBE, that carries the water discharged from the TURBINE.

THERM -- The equivalent of 100,000 BRITISH THERMAL UNITS (Btu).

THERMAL PLANT -- An electric generating plant which uses heat to produce electricity. Such plants may burn coal, gas, oil, biomass, or use nuclear energy to produce thermal energy.

TRANSFORMER -- A device used to change the voltage of ALTERNATING-CURRENT (AC) electricity.

TRANSMISSION -- The act or process of transporting ELECTRICAL ENERGY in bulk from a source or sources of supply to other principal parts of a system or to other utility systems.

TURBINE -- A machine in which the pressure or KINETIC ENERGY of flowing water is converted to mechanical energy which in turn can be converted to ELECTRICAL ENERGY by a GENERATOR.

ULTRAHIGH VOLTAGES (UHV) -- Voltages greater than 765,000 volts. See EXTRA HIGH VOLTAGE (EHV).

ULTRALOW HEAD -- HEAD of up to 3 metres (9.8 feet).

USCE -- U. S. Army Corps of Engineers.

USGS -- U. S. Geological Survey.

WATERSHED -- The region draining into a stream.

WATER TABLE -- The upper limit or surface of the GROUNDWATER.

WATER TREATMENT -- The purification of water to ensure its potability or safety for disposal, or to permit alternative use or reuse.

WEIR -- A dam in a stream to raise, divert the water, or to regulate the flow.

WHEELING -- The transportation of electricity by an electric utility over its lines for another utility.

WICKET GATES -- Gates at the entrance of a turbine used to control water flow into a TURBINE.

WORKING CAPITAL -- The amount of cash or other liquid assets that a company must have on hand to meet the current costs of operations until it is reimbursed by its customers. Sometimes the term is used to mean the difference between current and accrued assets and current and accrued liabilities.

WPRS -- U. S. Water and Power Resources Service (formerly U. S. Bureau of Reclamation).

YIELD -- the amount of water which can be supplied from a reservoir or a water source in a specified period.

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CONVERSION FACTORS

Quantity	To Convert from Metric Unit	To Customary Unit	Multiply Metric Unit By	To Convert to Metric Unit Multiply Customary Unit By
Length	millimetres (mm)	inches (in)	0 03937	25 4
	centimetres (cm) for snow depth	inches (in)	0 3937	2.54
	metres (m)	feet (ft)	3.2808	0.3048
	kilometres (km)	miles (mi)	0.62139	1.6093
Area	square millimetres (mm^2)	square inches (in^2)	0 00155	645.16
	square metres (m^2)	square feet (ft^2)	10.764	0 092903
	hectares (ha)	acres (ac)	2.4710	0.40469
	square kilometres (km^2)	square miles (mi^2)	0.3861	2.590
Volume	litres (L)	gallons (gal)	0 26417	3 7854
	megalitres	million gallons (10^6 gal)	0 26417	3 7854
	cubic metres (m^3)	cubic feet (ft^3)	35.315	0.028317
	cubic metres (m^3)	cubic yards (yd^3)	1.308	0.76455
	cubic dekametres (dam^3)	acre-feet (ac-ft)	0.8107	1.2335
Flow	cubic metres per second (m^3/s)	cubic feet per second (ft^3/s)	35 315	0.028317
	litres per minute (L/min)	gallons per minute (gal/min)	0 26417	3.7854
	litres per day (L/day)	gallons per day (gal/day)	0 26417	3.7854
	megalitres per day (ML/day)	million gallons per day (mgd)	0 26417	3 7854
	cubic dekametres per day (dam^3/day)	acre-feet per day (ac-ft/day)	0 8107	1 2335
Mass	kilograms (kg)	pounds (lb)	2 2046	0.45359
	megagrams (Mg)	tons (short, 2,000 lb)	1 1023	0.90718
Velocity	metres per second (m/s)	feet per second (ft/s)	3.2808	0.3048
Power	kilowatts (kW)	horsepower (hp)	1.3405	0.746
Pressure	kilopascals (kPa)	pounds per square inch (psi)	0. 14505	6 8948
	kilopascals (kPa)	feet head of water	0 33456	2.989
Specific Capacity	litres per minute per metre drawdown	gallons per minute per foot drawdown	0.08052	12.419
Concentration	milligrams per litre (mg/L)	parts per million (ppm)	1.0	1.0
Electrical Conductivity	microsiemens per centimetre (uS/cm)	micromhos per centimetre	1.0	1.0
Temperature	degrees Celsius (°C)	degrees Fahrenheit (°F)	(1 8 × °C)+32	(°F−32)/1.8

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